UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 8-K

Current Report

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 21, 2008

WASHINGTON MUTUAL, INC.

(Exact name of registrant as specified in its charter)

Commission File Number: 1-14667

WASHINGTON **(State or other jurisdiction of incorporation)**	**91-1653725** **(IRS Employer Identification No.)**

1301 SECOND AVENUE

SEATTLE, WASHINGTON 98101

(Address of principal executive offices, including zip code)

(206) 461-2000

(Registrant's telephone number, including area code)

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events

As previously disclosed, on October 28, 2008, Washington Mutual, Inc. (the "Company") and WMI Investment Corp. (together with the Company, the "Debtors") filed the *Motion of Debtors for an Order Pursuant to Section 365(a) of the Bankruptcy Code and Bankruptcy Rule 6006, Approving Rejection of Transfer Agreement* (the "Transfer Agreement Motion") with the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). Pursuant to the Transfer Agreement Motion, the Transfer Agent Agreement (the "Transfer Agreement"), dated as of January 3, 2005, between the

Company and Mellon Investor Services LLC ("Mellon") was to be terminated effective as of October 28, 2008.

On November 20, 2008, the Company submitted a revised order with the Bankruptcy Court with respect to the Transfer Agreement Motion (the "Order"). The Order was approved by the Bankruptcy Court on November 21, 2008 and the Transfer Agreement will now be terminated effective December 31, 2008. After December 31, 2008, Mellon will no longer act as the Company's transfer agent, and will not process requests to transfer the Company's securities.

Signature(s)

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

WASHINGTON MUTUAL, INC.

Date: November 25, 2008 By: /s/ William Kosturos
William Kosturos

Executive Vice President, Secretary and Chief Restructuring Officer

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Total Liabilities and Equity
$
10,950,357

$
5,431,511

$
5,975,419

$
464,609

$
(10,265,302
)

$
12,556,594

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Income Statement for the Three Months Ended September 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$199,100	$1,163,339	$60,873	$(1,623)	$1,421,689
Sales—Gas Royalty Interests	—	17,083	—	—	—	17,083
Sales—Purchased Gas	—	1,155	—	—	—	1,155
Freight—Outside	—	—	59,871	—	—	59,871
Other Income	232,472	(13,788)	33,414	1,412	(231,579)	21,931
Total Revenue and Other Income	232,472	203,550	1,256,624	62,285	(233,202)	1,521,729
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	23,375	106,331	667,100	58,401	24,061	879,268
Gas Royalty Interests Costs	—	15,420	—	—	(11)	15,409
Purchased Gas Costs	—	398	—	—	—	398
Related Party Activity	2,653	—	(8,346)	478	5,215	—
Freight Expense	—	—	59,871	—	—	59,871
Selling, General and Administrative Expenses	—	13,311	58,582	472	(25,673)	46,692
Depreciation, Depletion and Amortization	3,301	58,131	97,745	573	—	159,750
Interest Expense	58,421	2,332	(1,784)	13	(98)	58,884
Taxes Other Than Income	1,805	7,154	76,137	694	—	85,790
Abandonment of Long-Lived Assets	—	—	338	—	—	338
Transaction and Financing Fees	14,907	—	—	—	—	14,907
Total Costs	104,462	203,077	949,643	60,631	3,494	1,321,307
Earnings (Loss) Before Income Taxes	128,010	473	306,981	1,654	(236,696)	200,422
Income Tax Expense (Benefit)	(39,319)	(2,440)	74,226	626	—	33,093
Net Income (Loss)	$167,329	$2,913	$232,755	$1,028	$(236,696)	$167,329

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Balance Sheet at December 31, 2011:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Assets:						
Current Assets:						
Cash and Cash Equivalents	$37,342	$336,727	$1,269	$398	$—	$375,736
Accounts and Notes Receivable:						
Trade	—	63,299	500	399,013	—	462,812
Notes Receivables	2,669	311,754	527	—	—	314,950
Other Receivables	2,913	91,582	7,458	3,755	—	105,708
Inventories	—	8,600	206,096	43,639	—	258,335
Recoverable Income Taxes	—	—	—	—	—	—
Deferred Income Taxes	191,689	(50,606)	—	—	—	141,083
Prepaid Expenses	28,470	159,900	49,224	1,759	—	239,353
Total Current Assets	263,083	921,256	265,074	448,564	—	1,897,977
Property, Plant and Equipment:						
Property, Plant and Equipment	198,004	5,488,094	8,376,831	24,390	—	14,087,319
Less-Accumulated Depreciation, Depletion and Amortization	109,924	778,716	3,855,323	16,940	—	4,760,903
Total Property, Plant and Equipment-Net	88,080	4,709,378	4,521,508	7,450	—	9,326,416
Other Assets:						
Deferred Income Taxes	963,332	(455,608)	—	—	—	507,724
Restricted Cash	22,148	—	—	—	—	22,148
Investment in Affiliates	9,126,453	96,914	760,548	—	(9,801,879)	182,036
Notes Receivable	4,148	296,344	—	—	—	300,492
Other	116,624	110,128	52,009	10,146	—	288,907
Total Other Assets	10,232,705	47,778	812,557	10,146	(9,801,879)	1,301,307
Total Assets	$10,583,868	$5,678,412	$5,599,139	$466,160	$(9,801,879)	$12,525,700
Liabilities and Stockholders' Equity:						
Current Liabilities:						
Accounts Payable	$140,823	$206,072	$164,521	$10,587	$—	$522,003
Accounts Payable (Recoverable)-Related Parties	2,900,546	9,431	(3,222,648)	312,671	—	—
Current Portion of Long-Term Debt	805	5,587	13,543	756	—	20,691
Accrued Income Taxes	68,819	6,814	—	—	—	75,633
Other Accrued Liabilities	493,450	58,401	206,649	11,570	—	770,070
Total Current Liabilities	3,604,443	286,305	(2,837,935)	335,584	—	1,388,397
Long-Term Debt:	3,001,092	50,326	124,674	1,331	—	3,177,423
Deferred Credits and Other Liabilities:						
Postretirement Benefits Other Than Pensions	—	—	3,059,671	—	—	3,059,671
Pneumoconiosis Benefits	—	—	173,553	—	—	173,553
Mine Closing	—	—	406,712	—	—	406,712

Gas Well Closing	—	61,954	62,097	—	—	124,051
Workers' Compensation	—	—	150,786	248	—	151,034
Salary Retirement	269,069	—	—	—	—	269,069
Reclamation	—	—	39,969	—	—	39,969
Other	98,379	16,899	9,658	—	—	124,936
Total Deferred Credits and Other Liabilities	367,448	78,853	3,902,446	248	—	4,348,995
Total CONSOL Energy Inc. Stockholders' Equity	3,610,885	5,262,928	4,409,954	128,997	(9,801,879)	3,610,885
Total Liabilities and Equity	$10,583,868	$5,678,412	$5,599,139	$466,160	$(9,801,879)	$12,525,700

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Income Statement for the Nine Months Ended September 30, 2012 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$474,574	$2,919,814	$192,212	$(1,795)	$3,584,805
Sales—Gas Royalty Interests	—	34,707	—	—	—	34,707
Sales—Purchased Gas	—	2,443	—	—	—	2,443
Freight—Outside	—	—	126,195	—	—	126,195
Other Income	399,817	46,177	230,930	16,089	(399,817)	293,196
Total Revenue and Other Income	399,817	557,901	3,276,939	208,301	(401,612)	4,041,346
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	90,230	296,959	1,992,371	186,635	22,265	2,588,460
Gas Royalty Interests Costs	—	27,951	—	—	(35)	27,916
Purchased Gas Costs	—	2,123	—	—	—	2,123
Related Party Activity	1,575	—	5,078	1,376	(8,029)	—
Freight Expense	—	—	126,195	—	—	126,195
Selling, General and Administrative Expenses	—	29,199	79,169	1,044	—	109,412
Depreciation, Depletion and Amortization	8,901	148,343	304,245	1,559	—	463,048
Interest Expense	158,505	3,554	7,056	33	(360)	168,788
Taxes Other Than Income	159	24,790	229,381	2,213	—	256,543
Total Costs	259,370	532,919	2,743,495	192,860	13,841	3,742,485
Earnings (Loss) Before Income Taxes	140,447	24,982	533,444	15,441	(415,453)	298,861
Income Tax Expense (Benefit)	(98,120)	9,706	143,001	5,841	—	60,428
Net Income (Loss)	238,567	15,276	390,443	9,600	(415,453)	238,433
Add: Net Loss Attributable to Noncontrolling Interest	—	134	—	—	—	134
Net Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$238,567	$15,410	$390,443	$9,600	$(415,453)	$238,567

Income Statement for the Nine Months Ended September 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$566,272	$3,559,954	$171,027	$(4,086)	$4,293,167
Sales—Gas Royalty Interests	—	52,191	—	—	—	52,191
Sales—Purchased Gas	—	3,297	—	—	—	3,297
Freight—Outside	—	—	156,311	—	—	156,311
Other Income	629,116	(9,473)	55,051	20,008	(624,634)	70,068
Total Revenue and Other Income	629,116	612,287	3,771,316	191,035	(628,720)	4,575,034
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion, and amortization shown below)	86,775	284,908	2,012,261	166,106	70,326	2,620,376
Gas Royalty Interests Costs	—	46,620	—	—	(38)	46,582
Purchased Gas Costs	—	2,850	—	—	—	2,850
Related Party Activity	117	—	(21,083)	1,479	19,487	—
Freight Expense	—	—	156,122	—	—	156,122
Selling, General and Administrative Expenses	—	35,303	168,312	1,072	(74,376)	130,311
Depreciation, Depletion and Amortization	8,665	159,109	297,017	1,821	—	466,612
Interest Expense	178,849	7,564	3,799	40	(289)	189,963
Taxes Other Than Income	5,191	23,230	234,411	2,289	—	265,121
Abandonment of Long-Lived Assets	—	—	115,817	—	—	115,817
Loss on Debt Extinguishment	16,090	—	—	—	—	16,090
Transaction and Financing Fees	14,907	—	—	—	—	14,907
Total Costs	310,594	559,584	2,966,656	172,807	15,110	4,024,751
Earnings (Loss) Before Income Taxes	318,522	52,703	804,660	18,228	(643,830)	550,283
Income Tax Expense (Benefit)	(118,340)	18,029	206,837	6,895	—	113,421
Net Income (Loss)	$436,862	$34,674	$597,823	$11,333	$(643,830)	$436,862

Cash Flow for the Nine Months Ended September 30, 2012 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used In) Operating Activities	$(245,017)	$139,026	$635,257	$897	$—	$530,163
Cash Flows from Investing Activities:						
Capital Expenditures	$(40,863)	$(408,278)	$(702,880)	$—	$—	$(1,152,021)
Proceeds from Sales of Assets	169,500	359,636	54,756	50	—	583,942
Distributions from, net of (Investments In), Equity Affiliates	—	(31,650)	12,949	—	—	(18,701)
Net Cash (Used in) Provided by Investing Activities	$128,637	$(80,292)	$(635,175)	$50	$—	$(586,780)
Cash Flows from Financing Activities:						
Dividends (Paid) Received	$114,710	$(200,000)	$—	$—	$—	$(85,290)
Other Financing Activities	3,304	(4,107)	(1,729)	(339)	—	(2,871)
Net Cash (Used in) Provided by Financing Activities	$118,014	$(204,107)	$(1,729)	$(339)	$—	$(88,161)

Cash Flow for the Nine Months Ended September 30, 2011 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used In) Operating Activities	$515,622	$313,221	$425,702	$(2,141)	$—	$1,252,404
Cash Flows from Investing Activities:						
Capital Expenditures	$(26,578)	$(535,068)	$(435,817)	$—	$—	$(997,463)
Proceeds from Sales of Assets	10	688,505	5,304	1,472	—	695,291
Distributions from, net of (Investments In), Equity Affiliates	—	66,590	4,270	—	—	70,860
Net Cash (Used in) Provided by Investing Activities	$(26,568)	$220,027	$(426,243)	$1,472	$—	$(231,312)
Cash Flows from Financing Activities:						
Dividends Paid	$(67,972)	$—	$—	$—	$—	$(67,972)
Payments on Short-Term Borrowings	(155,000)	(129,000)	—	—	—	(284,000)
Payments on Securitization Facility	(200,000)	—	—	—	—	(200,000)
Proceeds from Issuance of Long-Term Notes	250,000	—	—	—	—	250,000
Payments on Long-Term Notes, including redemption premium	(265,785)	—	—	—	—	(265,785)
Debt Issuance and Financing Fees	(10,499)	(5,040)	—	—	—	(15,539)
Other Financing Activities	10,559	(7,044)	(994)	(588)	—	1,933
Net Cash (Used in) Provided by Financing Activities	$(438,697)	$(141,084)	$(994)	$(588)	$—	$(581,363)

Statement of Comprehensive Income for the Three Months Ended September 30, 2012 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net (Loss) Income	$(11,368)	$7,096	$47,157	$2,424	$(56,782)	$(11,473)
Other Comprehensive Income (Loss):						
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(8,684)	—	(8,684)	—	8,684	(8,684)
Amortization of Net Loss	16,605	—	16,605	—	(16,605)	16,605
Net (Decrease) Increase in the Value of Cash Flow Hedge	(6,459)	(6,459)	—	—	6,459	(6,459)
Reclassification of Cash Flow Hedges from OCI to Earnings	(47,809)	(47,809)	—	—	47,809	(47,809)
Other Comprehensive (Loss) Income:	(46,347)	(54,268)	7,921	—	46,347	(46,347)
Comprehensive (Loss) Income	(57,715)	(47,172)	55,078	2,424	(10,435)	(57,820)
Add: Comprehensive Loss Attributable to Noncontrolling Interest	—	105	—	—	—	105
Comprehensive (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(57,715)	$(47,067)	$55,078	$2,424	$(10,435)	$(57,715)

Statement of Comprehensive Income for the Three Months Ended September 30, 2011 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$167,329	$2,913	$232,755	$1,028	$(236,696)	$167,329
Other Comprehensive Income (Loss):						
Treasury Rate Lock	—	—	—	—	—	—
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(7,365)	—	(7,365)	—	7,365	(7,365)
Amortization of Net Loss	18,379	—	18,379	—	(18,379)	18,379
Net Increase (Decrease) in the Value of Cash Flow Hedge	59,620	59,620	—	—	(59,620)	59,620
Reclassification of Cash Flow Hedges from OCI to Earnings	(20,974)	(20,974)	—	—	20,974	(20,974)
Other Comprehensive Income (Loss):	49,660	38,646	11,014	—	(49,660)	49,660
Comprehensive Income (Loss)	$216,989	$41,559	$243,769	$1,028	$(286,356)	$216,989

Statement of Comprehensive Income for the Nine Months Ended September 30, 2012 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$238,567	$15,276	$390,443	$9,600	$(415,453)	$238,433
Other Comprehensive Income (Loss):						
Actuarially Determined Long-Term Liability Adjustments						
Change in Prior Service Cost	50,276	—	50,276	—	(50,276)	50,276
Amortization of Prior Service Cost	(24,921)	—	(24,921)	—	24,921	(24,921)
Amortization of Net Loss	49,725	—	49,725	—	(49,725)	49,725
Net Increase (Decrease) in the Value of Cash Flow Hedge	80,280	80,280	—	—	(80,280)	80,280
Reclassification of Cash Flow Hedges from OCI to Earnings	(153,597)	(153,597)	—	—	153,597	(153,597)
Other Comprehensive Income (Loss):	1,763	(73,317)	75,080	—	(1,763)	1,763
Comprehensive Income (Loss)	240,330	(58,041)	465,523	9,600	(417,216)	240,196
Add: Comprehensive Loss Attributable to Noncontrolling Interest	—	134	—	—	—	134
Comprehensive Income (Loss) Attributable to CONSOL Energy Inc. Shareholders'	$240,330	$(57,907)	$465,523	$9,600	$(417,216)	$240,330

Statement of Comprehensive Income for the Nine Months Ended September 30, 2011 (Unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$436,862	$34,674	$597,823	$11,333	$(643,830)	$436,862
Other Comprehensive Income (Loss):						
Treasury Rate Lock	(96)	—	—	—	—	(96)
Actuarially Determined Long-Term Liability Adjustments						
Amortization of Prior Service Cost	(22,094)	—	(22,094)	—	22,094	(22,094)
Amortization of Net Loss	55,135	—	55,135	—	(55,135)	55,135
Net Increase (Decrease) in the Value of Cash Flow Hedge	92,421	92,421	—	—	(92,421)	92,421
Reclassification of Cash Flow Hedges from OCI to Earnings	(56,719)	(56,719)	—	—	56,719	(56,719)
Other Comprehensive Income (Loss):	68,647	35,702	33,041	—	(68,743)	68,647
Comprehensive Income (Loss)	$505,509	$70,376	$630,864	$11,333	$(712,573)	$505,509

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NOTE 16—RELATED PARTY TRANSACTIONS:

CONE Gathering LLC Related Party Transactions

During the nine months ended September 30, 2012, CONE Gathering LLC (CONE), a 50% owned affiliate, provided CNX Gas Company gathering services in the ordinary course of business. Gathering services received from CONE were $5,895 and $13,619, for the three and nine months ended September 30, 2012, respectively, which were included in Cost of Goods Sold on the Consolidated Statements of Income.

As of September 30, 2012 and December 31, 2011, CONSOL Energy and CNX Gas Company had a net (payable) receivable of $(638) and $8,966, respectively, which were comprised of the following items:

	September, 30 2012	December 31, 2011	Location on Balance Sheet
CONE Gathering Capital Reimbursement	$ 1,422	$ 8,042	Accounts Receivable–Other
Reimbursement for CONE Expenses	263	2,009	Accounts Receivable–Other
Reimbursement for Services Provided to CONE	61	414	Accounts Receivable–Other
CONE Gathering Fee Payable	(2,384)	(1,499)	Accounts Payable
Net (Payable) Receivable due CONE	$ (638)	$ 8,966	

NOTE 17—RECENT ACCOUNTING PRONOUNCEMENTS:

In July 2012, the Financial Accounting Standards Board issued Update 2012-2 - Intangibles - Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment. The update is intended to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by simplifying how an entity tests those assets for impairment. The update is also intended to improve the consistency in impairment testing guidance among long-lived asset categories. Previous guidance required an entity to test indefinite-lived intangible assets for impairment by comparing the fair value of the asset with its carrying amount at least on an annual basis. If the carrying amount exceeded its fair value, an entity needed to recognize an impairment loss in the amount of the excess. The amendment to this update allows an entity to first assess the qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. This assessment will determine whether it is necessary to perform quantitative impairment tests. This type of testing results in guidance that is similar to the goodwill impairment testing in Update 2011-08. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012 with early adoption permitted for impairment tests performed as of July 27, 2012. We believe adoption of this new guidance will not have a material impact on CONSOL Energy's financial statements.

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

During the third quarter, the domestic coal and natural gas industries took steps to recover from the challenges of the past year. Although flat electric demand growth and global economic uncertainties persisted, more disciplined production from coal and natural gas producers and favorable weather helped reduce inventories and stabilize prices. The domestic thermal coal industry continues to work through the effects of low gas prices and the unusually warm 2011-2012 winter. Third quarter coal consumption was aided by above average temperatures in July. As natural gas prices began to rise above $3.00 per thousand cubic feet, more electric generation switched back to its traditional coal-fired generators. Early government estimates show that coal-fired generation produced 39% of the U.S. power generation sector during the third quarter compared with 42% during the same period in 2011. This third quarter figure is a 3% increase from the second quarter of 2012. The percentage remained constant between quarters two and three of 2011. Utility coal stockpiles also declined throughout the quarter versus earlier 2012 periods. Warmer summer temperatures, a rise in natural gas prices, and domestic coal production cuts began to stabilize coal prices.

In the longer term, the outlook for domestic thermal coal faces regulatory challenges. Even though policies continue to evolve and develop, they ultimately tend to favor greater adoption of natural gas-fired generation. Specifically, the Environmental Protection Agency (EPA) was forced to redefine the Cross-State Air Pollution Rule (CSAPR) after a federal circuit court overturned the proposed regulation. The CSAPR decision notwithstanding, few new coal plants are expected to be built and utilities will continue to retire smaller and less efficient units. Internationally, although Europe has continued to use cheaper coal for electric generation, U.S. thermal exports have faced foreign competition from Colombian and South African coals.

Also during the third quarter, metallurgical benchmark prices remained below the comparable 2011 period. Although the U.S. third quarter international settlement price for premium metallurgical coal increased 7% above the U.S. second quarter settlement, the benchmark has already settled lower for the U.S. fourth quarter. The continued low price environment is underscored by the resumption of Australian production and a slowdown of Chinese economic growth.

CONSOL Energy's coal sales outlook as of October 25, 2012 is as follows:

	Q4 2012	2012	2013	2014
Estimated Coal Sales (millions of tons)	14.0	55.9	56.7	61.8
Est. Low-Vol Met Sales	0.6	3.4	3.9	4.9
Tonnage: Firm	0.6	3.4	1.1	—
Avg. Price: Sold (Firm)	$134.64	$141.72	$130.35	$—
Est. High-Vol Met Sales	0.5	3.4	2.7	4.8
Tonnage: Firm	0.5	3.4	0.3	0.3
Avg. Price: Sold (Firm)	$81.07	$65.46	$73.23	$75.53
Est. Thermal Sales	12.9	49.1	49.5	51.4
Tonnage: Firm	12.6	48.8	35.9	14.9
Avg. Price: Sold (Firm)	$61.21	$61.66	$60.63	$62.27

Note: While most of the data in the table are single point estimates, the inherent uncertainty of markets and mining operations means that investors should consider a reasonable range around these estimates. N/A means not available or not forecast. CONSOL has chosen not to forecast prices for open tonnage due to ongoing customer negotiations. In the thermal sales category, the open tonnage includes two items: sold, but unpriced tons and collared tons. Collared tons in 2013 are 3.0 million tons, with a ceiling of $52.37 per ton and a floor of $47.37 per ton. Collared tons in 2014 are 7.0 million tons, with a ceiling of $55.90 per ton and a floor of $46.32 per ton. For 2013, when unpriced thermal tons are combined with collared tons, less than 2 million tons remains to be sold. Total Amonate estimated coal sales for Q4 2012 are 0.03 million tons. Calendar years 2012, 2013, and 2014 include 0.03, 0.6, and 0.7 million tons, respectively, from Amonate. The Amonate tons are not included in the category breakdowns.

Global steel demand has been under pressure and as a consequence, raw materials used to make steel are in less demand. In response to the weak market conditions related to raw materials used in steel making throughout its export markets in Asia, Europe, and South America, CONSOL Energy idled its Buchanan Mine and its Amonate Complex in early September 2012. The Buchanan Mine is expected to restart the week of November 5 with a five-day work week schedule, while Amonate is likely to

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remain idled for the remainder of 2012. Buchanan Mine typically produces approximately 400 thousand tons per month, while Amonate was expected to produce about 35 thousand tons per month.

On July 27, 2012 a structural failure occurred at CONSOL Energy's newly installed above-ground conveyor system at the Bailey Preparation Plant in Southwestern Pennsylvania. The belt system conveys coal from the Bailey and Enlow Fork mines to the Bailey Preparation Plant. This incident caused a total of four longwalls to be idled for approximately three weeks, at which point one rebuilt conveyor belt was re-started. Production from these mines was at approximately 60% of normal for most of the remainder of the third quarter. The company's third quarter net income would have been an estimated $53 million higher, had the conveyor belt incident not occurred. This impact is before the receipt of any insurance proceeds and any other proceeds under the indemnity provisions of the construction contract. Much lower sales from the company's flagship low-vol Buchanan Mine also reduced third quarter profitability, as the company chose not to sell into a market that was experiencing an inventory de-stocking.
In response to current weak market conditions for domestic coal, CONSOL Energy extended the annual miners' vacation period at its Blacksville No. 2 Mine and Robinson Run mines in Northern West Virginia. The Blacksville No. 2 Mine vacation period was extended for two weeks. Consistent with its core values of safety, compliance and continuous improvement, two belt rehabilitation projects were conducted during the extended vacation period. The longwall at Blacksville No. 2 Mine was restarted the week of July 22, 2012. The Robinson Run Mine extension was one week. Work was completed during the week extension to maintain the mine in a ready state. The longwall at Robinson Run Mine restarted the week of July 16, 2012. The extended vacation periods reduced total annual Company production by an estimated 300 thousand tons.
Also in response to the current weak market conditions for domestic coal and recent proposals and final rules adopted by the EPA, CONSOL Energy issued a notice under the Workers Adjustment and Retraining Notification Act (WARN) of a layoff at its Fola Operations near Bickmore, West Virginia. The layoffs were effective on September 1, 2012. Regular production from underground operations was idled on September 1, 2012. Production from the surface areas was idled as of June 29, 2012, and employees have been reassigned to reclamation activities. The idling of the Fola Complex reduced total annual Company production by approximately 800 thousand tons.
Due to market conditions, CONSOL Energy also idled the longwalls at Blacksville No. 2 and Buchanan Mine in March and April 2012. These longwalls resumed production on May 1, 2012.
Natural gas prices improved throughout the third quarter as horizontal gas targeted rigs deployed throughout the country dropped and storage levels, although still elevated, began to align more closely with the five year average. While production remains higher on a year over year basis, natural gas pricing has risen based on improving fundamentals and favorable weather. CONSOL Energy expects its 2012 net gas production to be between 157 - 159 Bcf. Fourth quarter 2012 gas production, net to CONSOL Energy, is expected to be approximately 42.5 - 44.5 Bcf.

The following developments impacting CONSOL Energy occurred in the nine months ended September 30, 2012:

- On October 30, 2012, CONSOL Energy Inc. issued notice under the Worker Adjustment and Retraining Notification Act (WARN) of its intent to idle its Miller Creek surface operations near Naugatuck, W. Va., resulting in a layoff impacting approximately 145 employees. Production from the Miller Creek surface operations was 1.2 million tons for the nine months ended September 30, 2012. The idling of the Miller Creek operations is due to a sequence of permit delays that has prevented the company from securing all of the necessary environmental permits required to continue mining as identified in the company's mine plan.

- In June 2012, CONSOL Energy announced that it acquired a non controlling interest in Epiphany Solar Water Systems, a privately-held company founded in New Castle, PA in 2009. Epiphany Solar Water Systems is testing what is believed to be the world's first concentrated solar powered water purification system. Under the agreement, CONSOL Energy has made an initial investment of $0.5 million and one of its Marcellus gas well locations in Greene County will serve as the site to pilot test this solar powered water purification system. The pilot test began in July with initial results expected in before the end of the year.

- In June 2012, CONSOL Energy sold its non-producing Northern Powder River Basin assets in southern Montana and northern Wyoming for $170 million in cash to Cloud Peak Energy. Additionally, CONSOL Energy retained an 8% production royalty interest on approximately 200 million tons of permitted fee coal. This transaction resulted in a pre-tax gain of $151 million.

- In June 2012, CONSOL Energy expanded an existing mining joint venture with a privately-held company in Central Pennsylvania. The joint venture will self-fund, through retained earnings, a $54 million (gross) expansion in 2012 and

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2013. The expansion will enable CONSOL Energy's share of high-vol A and mid-vol forecasted coal production to increase from 150,000 tons in 2012 to 900,000 tons in 2015.

- In April 2012, CONSOL Energy announced certain changes to the salaried other post-retirement benefit plan that current retirees and current active employees will receive as of January 1, 2014. The change provides a fixed annual retiree medical contribution into a Health Reimbursement Account for eligible employees. The money in the account can be used to help pay for a commercial medical plan, Medicare Part B and Part D premiums and other qualified expenses. Employees who work or worked in corporate or operational support positions at retirement and who are age 50 or older at December 31, 2013 will receive the revised benefit in lieu of the current retiree medical and prescription drug coverage. Employees who work or worked in corporate or operations support positions who are under age 50 at December 31, 2013 will receive no retiree medical or prescription drug benefit. CONSOL Energy remeasured the salaried other postretirement plan as of March 31, 2012 to recognize these changes. The remeasurement reflects the reduction in benefits and the change in discount rate from 4.51% at December 31, 2011 to 4.57% at March 31, 2012. The remeasurement resulted in a reduction of approximately $80.6 million of Other Post-Retirement Benefits (OPEB) liability with a corresponding offset to Other Comprehensive Income, net of applicable deferred taxes. The change resulted in a $6.3 million reduction in OPEB expense compared to what was originally expected to be recognized for the nine months ended September 30, 2012. Additionally, the change will result in a $3.1 million reduction to OPEB expense compared to what was originally expected to be recognized for the remaining three months of 2012. The change was made to align CONSOL Energy's corporate and operational support compensation package more closely with our peer group.

- Pennsylvania enacted Act 13 of 2012, which provides for the comprehensive regulation of Marcellus Shale development in Pennsylvania. Among other things, Act 13 requires an impact fee be paid annually on all nonconventional gas wells drilled in the state. The annual fee is based on annual average sales price and is modified annually for a 15-year period for each well. The impact fee also required the first year fee be paid on all applicable wells drilled before January 1, 2012 with subsequent annual fees to apply each year thereafter. CONSOL Energy's retroactive impact fee related to wells drilled prior to January 1, 2012 was approximately $4 million. This amount was paid in September 2012.

- In April 2012, CONSOL Energy sold its non-producing Elk Creek reserves in southern West Virginia. The transaction resulted in cash proceeds of $26 million and a gain on sale of assets of $11 million. In February 2012, CONSOL Energy sold it's non-producing Burning Star #4 reserves in Illinois. The transaction resulted in cash proceeds of $13 million and a gain on sale of assets of $11 million.

CONSOL Energy is managing several significant matters that may affect our business and impact our financial results in the future including the following:

- Challenges in the overall environment in which we operate create increased risks that we must continuously monitor and manage. These risks include (i) increased prices for commodities such as diesel fuel, synthetic rubber and steel that we use in our operations (although prices for some of these commodities declined during the quarter from previous quarters), (ii) increased scrutiny of existing safety regulations and the development of new safety regulations and (iii) additional environmental restrictions.

- Federal and state environmental regulators are reviewing our operations more closely and are more strictly interpreting and enforcing existing environmental laws and regulations, resulting in increased costs and delays. For example, we entered into a consent decree with the EPA and the West Virginia Department of Environmental Protection pursuant to which we agreed to construct an advanced technology mine water treatment plant and related facilities to reduce high levels of total dissolved chlorides in water discharges from certain of our mines in Northern West Virginia, at a total estimated cost of approximately $200 million. The new facility must be placed into service no later than May 2013.

Federal and state regulators have proposed regulations which, if adopted, would adversely impact our business. These proposed regulations could require significant changes in the manner in which we operate and/or would increase the cost of our operations. For example, the Department of Interior, Office of Surface Mining Reclamation and Enforcement (OSM) is currently preparing an environmental impact statement relating to OSM's consideration of five alternatives for amending its coal mining stream protection rules. All of the alternatives, except the no action alternative, could make it more costly to mine our coal and/or could eliminate the ability to mine some of our coal. Another example is the Mercury and Air Toxic Standards issued by the EPA on December 16, 2011. The new regulations set mercury and air toxic standards for new and existing coal and oil fired electric utility steam generating units and include more stringent new source performance standards (NSPS) for particulate matter (PM), SO2 and

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NOx. Some older coal fired power plants may be retired or have operation time reduced rather than install additional expensive emission controls which could reduce the amount of coal consumed. On April 18, 2012, the EPA published new final New Source Performance Standards for gas wells and related facilities. These rules apply to wells that were hydraulically fractured after August, 23, 2011 and require the implementation by January 1, 2015 of technologies that capture the gas that is currently vented or flared during completion (hydrofracturing) of a well. Low pressure wells, including coalbed methane wells, are excluded from these new standards.

- In April 2012, the EPA published its proposed New Source Performance Standards (NSPS) for carbon dioxide emissions from coal powered electric generating units. The public comment period has run and publication of the final rules is expected soon. The proposed rules will apply to new power plants and to existing plants that make major modifications. If the rules are adopted as proposed, the only new coal fired power plants that will be able to meet the proposed emission limits will be coal fired plants with carbon dioxide capture and storage (CCS). Commercial scale CCS is not likely to be available in the near future, and if available, it may make coal fired electric generation units uneconomical compared to new gas fired electric generation units. Thus, if finalized the proposed rules could seriously threaten the construction of new coal fired electric generating units.

- On May 25, 2012, CONSOL Energy received a citizens' Notice of Intent to Sue from the Sierra Club, the Ohio Valley Environmental Coalition and the West Virginia Highlands Conservancy alleging violations of the Clean Water Act relating to selenium at its Fola mining complex in central West Virginia. On June 5, 2012, the West Virginia Department of Environmental Protection issued an Administrative Order to Fola. Fola is complying with the Administrative Order. On September 4, 2012, the citizens group filed a complaint against Fola in the U.S District Court for the Southern District of West Virginia covering the same matters addressed in the State Administrative Order.

- In late June, CONSOL Energy received informal notification from the Pennsylvania Department of Environmental Protection of the Department's intent pursuant to a Technical Guidance Document entitled “Surface Water Protection-Underground Bituminous Coal Mining” to require a change in the mine plan of a pending application for a permit for expansion of the Company's Bailey East longwall mine. If ultimately required, this change in mine plan could have a material effect on CONSOL Energy's forecasted production for 2015. Although CONSOL Energy does not agree that a modification of its mining plan is necessary to comply with applicable regulatory performance standards, CONSOL Energy is currently reviewing the notification and any modifications that would be required if CONSOL Energy is compelled to modify its application.

- CONSOL Energy continues to explore potential sales of non-core assets.

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Results of Operations
Three Months Ended September 30, 2012 Compared with Three Months Ended September 30, 2011

Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net loss of $11 million, or $0.05 per diluted share, for the three months ended September 30, 2012. Net income was $167 million, or $0.73 per diluted share, for the three months ended September 30, 2011.
The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $4 million of earnings before income tax for the three months ended September 30, 2012 compared to $269 million for the three months ended September 30, 2011. The coal division sold 12.3 million tons of coal produced from CONSOL Energy mines for the three months ended September 30, 2012 compared to 14.7 million tons for the three months ended September 30, 2011.
The average sales price and average costs per ton for all active coal operations were as follows:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per ton sold	$67.31	$76.60	$(9.29)	(12.1)%
Average Costs per ton sold	55.84	54.35	1.49	2.7%
Margin	$11.47	$22.25	$(10.78)	(48.4)%

The average sales price per ton sold was lower in the period-to-period comparison due to weakened pricing in the metallurgical coal markets, slightly offset by higher thermal coal average prices as a result of several successful re-negotiations of domestic thermal contracts where pricing took effect on January 1, 2012. The decreased sales tonnage is due to decreased coal demand in both thermal and metallurgical markets and curtailed shipments due to the Bailey Belt incident discussed previously.

Changes in the average cost of goods sold per ton were primarily related to the following items:

- Average cost of goods sold per ton increased due to fewer tons sold. Fixed costs are allocated over fewer sales tons, resulting in higher unit costs.
- Average labor and labor-related costs per ton sold increased as a result of the impact of the $1.00 per hour worked United Mine Workers of America (UMWA) contract wage increases, offset, in part, by fewer hours worked.
- Average depreciation, depletion and amortization per ton sold increased due to additional assets placed into service after the 2011 period.
- Average retirement and disability costs per ton sold decreased due to the improvement in other postretirement benefits discussed in the long-term liabilities section below.

The total gas division includes coalbed methane (CBM), shallow oil and gas, Marcellus and other gas. The total gas division contributed $12 million of earnings before income tax for the three months ended September 30, 2012. The total gas division did not contribute a significant amount to earnings for the three months ended September 30, 2011. Total gas production was 39.5 billion cubic feet for the three months ended September 30, 2012 compared to 40.4 billion cubic feet for the three months ended September 30, 2011. Total gas sales decreased as a result of a decrease of 4.5 billion net cubic feet of production related to both the 2011 divestiture of Antero Resources Appalachian Corp. (Antero) and the 2011 Noble Joint Venture. Total production also decreased as a result of the Buchanan Mine idling as previously discussed. These decreases were offset, in part, by the on-going drilling program. See Note 2—Acquisitions and Dispositions in the Notes to the Unaudited Consolidated Financial Statements for additional details on the Antero and Noble transactions.

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The average sales price and average costs for all active gas operations were as follows:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$4.19	$4.92	$(0.73)	(14.8)%
Average Costs per thousand cubic feet sold	3.38	3.60	(0.22)	(6.1)%
Margin	$0.81	$1.32	$(0.51)	(38.6)%

Total gas division outside sales revenue was $165 million for the three months ended September 30, 2012 compared to $199 million for the three months ended September 30, 2011. The $34 million decrease was primarily due to the 14.8% reduction in average sales price. The decrease in average sales price is the result of lower general market prices for natural gas, offset, in part, by various gas swap transactions maturing in each period. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 19.3 billion cubic feet of produced gas sales volumes for the three months ended September 30, 2012 at an average price of $5.25 per thousand cubic feet. These financial hedges represented 23.9 billion cubic feet of produced gas sales volumes for the three months ended September 30, 2011 at an average price of $5.12 per thousand cubic feet.

Changes in the average cost per thousand cubic feet of gas sold were primarily related to the following items:

- Lower lifting costs that were the result of decreased road maintenance, decreased well fishing and well tending costs.
- Lower units-of-production depreciation, depletion and amortization rates for producing properties. These rates were generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. Increased proved and proved developed reserves relative to the net book value of the producing assets resulted in a lower units-of-production rate.
- Lower direct administrative, selling and other costs per unit attributable to decreased actual dollars as a result of a reduction in direct administrative labor and other costs.
- Gathering costs increased in the period-to-period comparison due to increased transportation charges.

The other segment includes industrial supplies activity, terminal, river and dock service activity, income taxes and other business activities not assigned to the coal or gas segment.

At the beginning of 2012, management decided that it would no longer consider general and administrative costs on a segment by segment basis as a factor in their decision making process. These decisions include allocation of capital and individual segment profit performance results. Management also concluded that general and administrative costs would continue to be considered in results at the divisional level (total coal and total gas). In order to present financial information in a manner consistent with internal management's evaluations, the prior periods general and administrative costs have been reclassified to reflect information consistent with the current year's presentation. The total divisional results have not changed. Individual segment results within the division have been recast to reflect costs excluding general and administrative. General and administrative costs are excluded from the coal and gas unit costs above. As in the prior periods, general and administrative costs are allocated between divisions (Coal, Gas, Other) based primarily on percentage of total revenue and percentage of total projected capital expenditures. The total general and administrative costs were made up of the following items:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Employee wages and related expenses	$14	$17	$(3)	(17.6)%
Consulting and professional services	8	9	(1)	(11.1)%
Contributions	1	4	(3)	(75.0)%
Miscellaneous	10	10	—	—%
Total Company General and Administrative Expenses	$33	$40	$(7)	(17.5)%

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Total Company General and Administrative Expenses changed due to the following:

- Employee wages and related expenses decreased $3 million in the period-to-period comparison primarily attributable to lower salary other post-retirement benefit expenses in the period-to-period comparison. The lower expenses relate to changes in the discount rates and other assumptions. Additionally, an other post employment benefit plan modification for certain salaried employees lowered expenses.
- Consulting and professional services decreased $1 million in the period-to-period comparison primarily due to a reduction in CONSOL Energy's advertising and promotion campaign.
- Contributions decreased $3 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Miscellaneous general and administrative expenses were consistent in the period-to-period comparison due to various corporate projects that occurred throughout both periods, none of which were individually material.

Included in both coal and gas unit costs are total Company long-term liabilities, such as other postretirement benefits (OPEB), the salary retirement plan, workers' compensation and long-term disability. These long-term liabilities costs are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Total CONSOL Energy expense related to our actuarial calculated liabilities was $64 million for the three months ended September 30, 2012 compared to $83 million for the three months ended September 30, 2011. The decrease of $19 million for total CONSOL Energy expense was primarily due to a decrease in the discount rate assumptions used to calculate expense for benefit plans at the measurement date, which is December 31. Additionally, a part of the decrease was due to a plan modification for the salaried other post-retirement benefit plan which required a remeasurement as of March 31, 2012. See Note 3—Components of Pension and Other Postretirement Benefit Plans Net Periodic Benefit Costs and Note 4—Components of Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation Net Periodic Benefit Costs in the Notes to the Unaudited Consolidated Financial Statements for additional detail of the total Company expense decrease.

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TOTAL COAL SEGMENT ANALYSIS for the three months ended September 30, 2012 compared to the three months ended September 30, 2011:

The coal segment contributed $4 million of earnings before income tax for the three months ended September 30, 2012 compared to $269 million for the three months ended September 30, 2011. Variances by the individual coal segments are discussed below.

	For the Three Months Ended September 30, 2012					Difference to Three Months Ended September 30, 2011				
	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$667	$48	$110	$—	$825	$(65)	$(35)	$(198)	$(8)	$(306)
Purchased Coal	—	—	—	5	5	—	—	—	—	—
Total Outside Sales	667	48	110	5	830	(65)	(35)	(198)	(8)	(306)
Freight Revenue	—	—	—	27	27	—	—	—	(33)	(33)
Other Income	1	1	—	18	20	—	(2)	—	(6)	(8)
Total Revenue and Other Income	668	49	110	50	877	(65)	(37)	(198)	(47)	(347)
Costs and Expenses:										
Beginning inventory costs	109	2	26	—	137	18	2	11	—	31
Total direct costs	333	22	45	74	474	(42)	(15)	(9)	41	(25)
Total royalty/production taxes	45	2	7	—	54	(4)	(2)	(10)	(2)	(18)
Total direct services to operations	51	5	6	65	127	(15)	(2)	—	8	(9)
Total retirement and disability	40	3	7	9	59	(17)	(2)	(4)	5	(18)
Depreciation, depletion and amortization	67	5	9	15	96	(8)	(2)	—	11	1
Ending inventory costs	(67)	—	(33)	(1)	(101)	15	—	(25)	(1)	(11)
Total Costs and Expenses	578	39	67	162	846	(53)	(21)	(37)	62	(49)
Freight Expense	—	—	—	27	27	—	—	—	(33)	(33)
Total Costs	578	39	67	189	873	(53)	(21)	(37)	29	(82)
Earnings (Loss) Before Income Taxes	$90	$10	$43	$(139)	$4	$(12)	$(16)	$(161)	$(76)	$(265)

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THERMAL COAL SEGMENT

The thermal coal segment contributed $90 million to total Company earnings before income tax for the three months ended September 30, 2012 compared to $102 million for the three months ended September 30, 2011. The thermal coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced Thermal Tons Sold (in millions)	10.7	12.2	(1.5)	(12.3)%
Average Sales Price Per Thermal Ton Sold	$62.11	$60.18	$1.93	3.2%
Beginning Inventory Costs Per Thermal Ton	$56.03	$56.92	$(0.89)	(1.6)%
Total Direct Operating Costs Per Thermal Ton Produced	$33.05	$30.91	$2.14	6.9%
Total Royalty/Production Taxes Per Thermal Ton Produced	4.46	4.07	0.39	9.6%
Total Direct Services to Operations Per Thermal Ton Produced	5.06	5.44	(0.38)	(7.0)%
Total Retirement and Disability Per Thermal Ton Produced	4.04	4.70	(0.66)	(14.0)%
Total Depreciation, Depletion and Amortization Costs Per Thermal Ton Produced	6.70	6.22	0.48	7.7%
Total Production Costs Per Thermal Ton Produced	$53.31	$51.34	$1.97	3.8%
Ending Inventory Costs Per Thermal Ton	$51.55	$52.89	$(1.34)	(2.5)%
Total Costs Per Thermal Ton Sold	$53.81	$51.94	$1.87	3.6%
Average Margin Per Thermal Ton Sold	$8.30	$8.24	$0.06	0.7%

Thermal coal revenue was $667 million for the three months ended September 30, 2012 compared to $732 million for the three months ended September 30, 2011. The $65 million decrease was attributable to a 1.5 million reduction in thermal tons sold offset, in part, by a $1.93 per ton higher average sales price. The sales ton decrease was primarily due to the July 27, 2012 structural failure of the above-ground conveyor system at the Bailey Preparation Plant. The incident curtailed shipments of production from both Bailey Mine and the Enlow Fork Mine during the reconstruction period as previously discussed. Thermal coal average sales price per ton were higher in the period-to-period comparison as a result of several successful re-negotiations of domestic thermal contracts whose pricing took effect on January 1, 2012.

Other income attributable to the thermal coal segment represents earnings from our equity affiliates that operate thermal coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Total cost of goods sold are comprised of changes in thermal coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for thermal coal was $578 million for the three months ended September 30, 2012, or $53 million lower than the $631 million for the three months ended September 30, 2011. Although total cost of goods sold dollars were improved, total costs per ton sold was impaired. Total costs of goods sold for thermal coal was $53.81 per ton in the three months ended September 30, 2012 compared to $51.94 per ton in the three months ended September 30, 2011. The increase in cost of goods sold per thermal ton produced were due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Direct Operating costs related to the thermal coal segment were $333 million in the three months ended September 30, 2012 compared to $375 million in the three months ended September 30, 2011.

Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and cost control measures implemented. Although improved $42 million, the cost improvements did not completely offset the impact of reduced production on unit costs. Direct operating costs were $33.05 per ton produced in the current period compared to $30.91 per ton produced in the

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prior period. Changes in the average direct operating costs per thermal ton produced were primarily related to the following items:

- Average operating costs per thermal ton produced increased due to fewer tons produced. Fixed costs are allocated over less tons, resulting in higher unit costs.
- Labor and related benefits average costs per thermal ton produced increased. This was primarily due to the impact of the wage increases of $1.00 per hour worked related to the UMWA collective bargaining agreement in the period-to-period comparison, offset, in part, by fewer overtime hours worked.
- Various other unit costs including supplies, maintenance, power and miscellaneous costs did not significantly change individually or in total.

Royalties and production taxes were $45 million in the three months ended September 30, 2012 compared to $49 million in the three months ended September 30, 2011. Although improved $4 million, these costs were impaired on a unit basis. Average cost per thermal ton produced increased $0.39 per ton due to lower production volumes and higher average sales prices which is the basis for most production taxes and royalty calculations.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The cost of these support services were $51 million in the current period compared to $66 million in the prior year period. Direct services to the operations were $5.06 per ton in the current period compared to $5.44 per ton in the prior period. Changes in the average direct services to operations cost per ton for thermal coal sold were primarily related to the following items:

- Subsidence average cost per thermal ton produced is lower in the period-to-period comparison due to the timing and quantity of structures undermined. Also, subsidence expense is lower in the current period due to less streams being undermined compared to the prior year quarter.
- Unit costs were also improved due to various other items, none of which were individually material.
- Average direct service costs to operations were impaired due to lower thermal tons produced in the period-to-period comparison which negatively impacted unit costs.

Retirement and disability costs are comprised of the expenses related to the Company's long-term liabilities, such as other OPEB, the salary retirement plan, workers' compensation, coal workers' pneumoconiosis (CWP) and long-term disability. These liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. The average retirement and disability costs attributable to the thermal coal segment were $40 million for the three months ended September 30, 2012 compared to $57 million for the three months ended September 30, 2011. The decrease in the thermal coal retirement and disability costs was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. This improvement was offset, in part, by the reduction in production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the thermal coal segment was $67 million for the three months ended September 30, 2012 compared to $75 million for the three months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per thermal ton produced were higher in the three months ended September 30, 2012 compared to the three months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis.

Changes in thermal coal inventory volumes and carrying value resulted in $42 million of cost of goods sold in the three months ended September 30, 2012 compared to $9 million in the three months ended September 30, 2011. Thermal coal inventory was 1.3 million tons at September 30, 2012 compared to 1.6 million tons at September 30, 2011.

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HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $10 million to total Company earnings before income tax for the three months ended September 30, 2012 compared to $26 million for the three months ended September 30, 2011. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced High Vol Met Tons Sold (in millions)	0.7	1.0	(0.3)	(30.0)%
Average Sales Price Per High Vol Met Ton Sold	$67.76	$82.21	$(14.45)	(17.6)%
Beginning Inventory Costs Per High Vol Met Ton	$63.50	$—	$63.50	—%
Total Direct Operating Costs Per High Vol Met Ton Produced	$30.10	$36.19	$(6.09)	(16.8)%
Total Royalty/Production Taxes Per High Vol Met Ton Produced	3.09	4.11	(1.02)	(24.8)%
Total Direct Services to Operations Per High Vol Met Ton Produced	7.26	7.33	(0.07)	(1.0)%
Total Retirement and Disability Per High Vol Met Ton Produced	3.89	5.43	(1.54)	(28.4)%
Total Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Produced	7.38	7.22	0.16	2.2%
Total Production Costs Per High Vol Met Ton Produced	$51.72	$60.28	$(8.56)	(14.2)%
Ending Inventory Costs Per High Vol Met Ton	$—	$—	$—	—%
Total Costs Per High Vol Met Ton Sold	$55.29	$60.28	$(4.99)	(8.3)%
Margin Per High Vol Met Ton Sold	$12.47	$21.93	$(9.46)	(43.1)%

High volatile metallurgical coal revenue was $48 million for the three months ended September 30, 2012 compared to $83 million for the three months ended September 30, 2011. Average sales prices for high volatile metallurgical coal decreased $14.45 per ton compared to the three months ended September 30, 2011 due to weakened global metallurgical coal demand. CONSOL Energy priced 0.6 million tons of high volatile metallurgical coal in the export market at an average sales price of $65.96 per ton for the three months ended September 30, 2012 compared to 0.8 million tons at an average price of $80.65 per ton for the three months ended September 30, 2011. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in high volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for high volatile metallurgical coal was $39 million for the three months ended September 30, 2012, or $21 million lower than the $60 million for the three months ended September 30, 2011. Total cost of goods sold for high volatile metallurgical coal was $55.29 per ton in the three months ended September 30, 2012 compared to $60.28 per ton in the three months ended September 30, 2011. The decrease in cost of goods sold per high volatile metallurgical ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Direct Operating costs related to the high volatile metallurgical coal segment were $22 million in the three months ended September 30, 2012 compared to $37 million in the three months ended September 30, 2011. Direct operating costs were $30.10 per ton produced in the current period compared to $36.19 per ton produced in the prior period. Changes in the average direct operating costs per ton for high volatile metallurgical coal sold were primarily related to the mix of mines which sold on the high volatile metallurgical coal market in the period-to-period comparison. Mines with higher cost structures produced a larger portion of the high volatile metallurgical coal shipped in the prior period compared to the current period. This resulted in lower direct operating costs in the period-to-period comparison. The impact of the improvements on unit costs were offset, in part, by lower tons sold which negatively impacted unit costs.

Royalties and production taxes improved $2 million to $2 million in the current period compared to $4 million in the prior period. Unit costs also improved $1.02 per high volatile metallurgical ton produced to $3.09 per ton in the current period

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compared to $4.11 per ton in the prior period. Average cost per high volatile metallurgical ton produced decreased due to lower production taxes related to lower average sales prices.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for high volatile metallurgical coal were $5 million in the current period compared to $7 million in the prior period. The improvement was due primarily to lower direct administrative costs and subsidence costs. Direct services to the operations for high volatile metallurgical coal were $7.26 per ton in the current period compared to $7.33 per ton in the prior period. These improvements lowered unit costs, but were offset in part by lower tons produced in the period-to-period comparison.

Retirement and disability costs are comprised of the expenses related to the Company's long-term liabilities, such as other post-retirement benefits (OPEB), the salary retirement plan, workers' compensation, coal workers' pneumoconiosis (CWP) and long-term disability. These liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. The average retirement and disability costs attributable to the high volatile metallurgical coal segment were $3 million for the three months ended September 30, 2012 compared to $5 million for the three months ended September 30, 2011. The decrease in the high volatile metallurgical coal retirement and disability costs was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. This improvement was offset, in part, by the reduction in production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $5 million for the three months ended September 30, 2012 compared to $7 million for the three months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per high volatile ton produced were higher in the three months ended September 30, 2012 compared to the three months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis.

Changes in high volatile metallurgical coal inventory volumes and carrying value resulted in $2 million of cost of goods sold in the three months ended September 30, 2012. There were no changes in volumes or carrying value in the three months ended September 30, 2011. There was no high volatile metallurgical coal inventory at September 30, 2012 or September 30, 2011.

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LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $43 million to total Company earnings before income tax for the three months ended September 30, 2012 compared to $204 million for the three months ended September 30, 2011. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced Low Vol Met Tons Sold (in millions)	0.8	1.4	(0.6)	(42.9)%
Average Sales Price Per Low Vol Met Ton Sold	$135.66	$207.21	$(71.55)	(34.5)%
Beginning Inventory Costs Per Low Vol Met Ton	$69.84	$66.09	$3.75	5.7 %
Total Direct Operating Costs Per Low Vol Met Ton Produced	$55.60	$39.28	$16.32	41.5 %
Total Royalty/Production Taxes Per Low Vol Met Ton Produced	8.75	12.42	(3.67)	(29.5)%
Total Direct Services to Operations Per Low Vol Met Ton Produced	6.83	4.46	2.37	53.1 %
Total Retirement and Disability Per Low Vol Met Ton Produced	8.63	7.58	1.05	13.9 %
Total Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Produced	11.29	6.73	4.56	67.8 %
Total Production Costs Per Low Vol Met Ton Produced	$91.10	$70.47	$20.63	29.3 %
Ending Inventory Costs Per Low Vol Met Ton	$87.32	$67.35	$19.97	29.7 %
Total Costs Per Low Vol Met Ton Sold	$83.09	$70.08	$13.01	18.6 %
Margin Per Low Vol Met Ton Sold	$52.57	$137.13	$(84.56)	(61.7)%

Low volatile metallurgical coal revenue was $110 million for the three months ended September 30, 2012 compared to $308 million for the three months ended September 30, 2011. The $198 million decrease was attributable to the 0.6 million decrease in sales tons and a $71.55 per ton decrease in average sales price. CONSOL Energy priced 0.6 million tons of low volatile metallurgical coal in the export market at an average sales price of $114.26 per ton for the three months ended September 30, 2012 compared to 1.2 million tons at an average price of $214.74 per ton for the three months ended September 30, 2011. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in low volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for low volatile metallurgical coal was $67 million for the three months ended September 30, 2012, or $37 million lower than the $104 million for the three months ended September 30, 2011. Total cost of goods sold for low volatile metallurgical coal was $83.09 per ton in the three months ended September 30, 2012 compared to $70.08 per ton in the three months ended September 30, 2011. The increase in costs of goods sold per low volatile metallurgical ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Direct Operating costs related to the low volatile metallurgical coal segment were $45 million in the three months ended September 30, 2012 compared to $54 million in the three months ended September 30, 2011. Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and cost control measures implemented. Although improved $9 million, the cost improvements did not completely offset the impact of reduced production on unit costs. Direct operating costs were $55.60 per ton produced in the current period compared to $39.28 per ton produced in the prior period. Low volatile metallurgical coal production was 0.8 million tons in the three months ended September 30, 2012 compared to 1.4 million tons in the three months ended September 30, 2011. Production was lower in the period-to-period comparison due to the Buchanan Mine being idled in early September. The mine was idled in response to the weak world economy. Fixed costs were then spread over fewer tons produced which increased all costs on a per unit basis.

Royalties and production taxes improved $10 million to $7 million in the current period compared to $17 million in the prior period. Unit costs also improved $3.67 per low volatile metallurgical ton produced to $8.75 per ton in the current period

compared to $12.42 per ton in the prior period. Average cost per low volatile metallurgical ton produced decreased due to lower royalties and lower production taxes. These decreases were related to lower volumes produced and lower average sales prices.
Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for low volatile metallurgical coal were $6 million in both the current and prior periods. Direct services to the operations for low volatile metallurgical coal were $6.83 per ton in the current period compared to $4.46 per ton in the prior period. Changes in the average direct service to operations cost per ton for low volatile metallurgical coal produced were primarily related to lower tons produced in the period-to-period comparison.
Retirement and disability costs are comprised of the expenses related to the Company's long-term liabilities, such as other post-retirement benefits (OPEB), the salary retirement plan, workers' compensation, coal workers' pneumoconiosis (CWP) and long-term disability. These liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. The retirement and disability costs attributable to the low volatile metallurgical coal segment were $7 million for the three months ended September 30, 2012 compared to $11 million for the three months ended September 30, 2011. The decrease in the low volatile metallurgical retirement and disability costs was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. This improvement was offset, in part, by the reduction in production volumes which negatively impacted unit costs.
Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $9 million for both the three months ended September 30, 2012 and 2011. Unit costs per low volatile metallurgical ton produced were higher in the three months ended September 30, 2012 compared to the three months ended September 30, 2011 due to lower tons produced.
Changes in low volatile metallurgical coal inventory volumes and carrying value resulted in a reduction of $7 million to cost of goods sold in the three months ended September 30, 2012 and an increase of $7 million to cost of goods sold in the three months ended September 30, 2011. Produced low volatile metallurgical coal inventory was 0.4 million tons at September 30, 2012 compared to 0.1 million tons at September 30, 2011.
OTHER COAL SEGMENT
The other coal segment had a loss before income tax of $139 million for the three months ended September 30, 2012 compared to a loss before income tax of $63 million for the three months ended September 30, 2011. The other coal segment includes purchased coal activities, idle mine activities, coal general and administrative costs as well as various activities assigned to the coal division but not allocated to each individual mine.
Produced coal sales include revenue from the sale of less than 0.1 million tons for the three months ended September 30, 2012 compared to 0.1 million tons for the three months ending September 30, 2011. The primary focus of the activity at these locations is reclaiming disturbed land in accordance with the mining permit requirements after final mining has occurred. The tons sold were incidental to total Company production or sales.
Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes to meet customer coal specifications and coal purchased from third parties and sold directly to our customers. The revenues were $5 million for the three months ended September 30, 2012 and September 30, 2011.
Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is offset in freight expense. Freight revenue was $27 million for the three months ended September 30, 2012 compared to $60 million for the three months ended September 30, 2011. The $33 million decrease in freight revenue is due to decreased shipments on contracts for which CONSOL Energy contractually provides transportation services.
Miscellaneous other income was $18 million for the three months ended September 30, 2012 compared to $24 million for the three months ended September 30, 2011. Other revenue in the three months ended September 30, 2011 includes a gain of $10 million for the issuance of a pipeline right-of-way to a third party. This impairment was offset

by $5 million of income from certain thermal coal contract buyouts received during the three months ended September 30, 2012. Various other transactions, which occurred throughout both periods, none of which were individually material, resulted in an impairment of $1 million.

Other coal segment total costs were $189 million for the three months ended September 30, 2012 compared to $160 million for the three months ended September 30, 2011. The increase of $29 million was due to the following items:

	For the Three Months Ended September 30,		
	2012	2011	Variance
Bailey Belt Incident	$42	$—	$42
Closed and idle mines	40	23	17
Purchased coal	11	10	1
Freight expense	27	60	(33)
Other	69	67	2
Total Other Coal Segment Costs	$189	$160	$29

- Bailey Belt Incident costs represent expenses for various projects that were incurred during the belt-reconstruction period related to continued advancement of the mines and on-going projects at the mines.
- Closed and idle mine costs increased approximately $17 million for the three months ended September 30, 2012 compared to the three months ended September 30, 2011. Closed and idle mine costs increased $11 million due to the decision to idle operations at Fola Surface and $7 million due to the decision to idle operations at Buchanan Mine during September 2012. Closed and idle mine costs decreased $1 million due to other changes in operational status of various other mines, between idled and operating throughout both periods, none of which were individually material.
- Purchased coal costs increased approximately $1 million in the period-to-period comparison due to various items, none of which were individually material.
- Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used for the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight expense is offset in freight revenue. Freight expense decreased $33 million primarily due to decreased shipments on contracts for which CONSOL Energy contractually provides transportation services.
- Other expenses related to the coal segment increased $2 million in the period-to-period comparison due to various transactions which occurred throughout both periods, none of which were individually material.

TOTAL GAS SEGMENT ANALYSIS for the three months ended September 30, 2012 compared to the three months ended September 30, 2011:

The total gas segment contributed $12 million to the total Company earnings before income tax for the three months ended September 30, 2012. The gas segment did not significantly contribute to earnings before income tax for the three months ended September 30, 2011.

	For the Three Months Ended September 30, 2012					Difference to Three Months Ended September 30, 2011				
	CBM	Shallow Oil & Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil & Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$94	$32	$36	$2	$164	$(23)	$(7)	$(3)	$—	$(33)
Related Party	1	—	—	—	1	(1)	—	—	—	(1)
Total Outside Sales	95	32	36	2	165	(24)	(7)	(3)	—	(34)
Gas Royalty Interest	—	—	—	13	13	—	—	—	(4)	(4)
Purchased Gas	—	—	—	1	1	—	—	—	—	—
Other Income	—	—	—	12	12	—	—	—	26	26
Total Revenue and Other Income	95	32	36	28	191	(24)	(7)	(3)	22	(12)
Lifting	9	10	3	—	22	(1)	(5)	(3)	—	(9)
Ad Valorem, Severance, and Other Taxes	2	2	1	2	7	(1)	—	1	1	1
Gathering	27	6	7	1	41	2	(2)	4	1	5
Gas Direct Administrative, Selling & Other	3	3	6	(1)	11	(5)	(2)	3	—	(4)
Depreciation, Depletion and Amortization	23	14	13	2	52	(3)	(1)	(2)	—	(6)
General & Administration	—	—	—	10	10	—	—	—	(3)	(3)
Gas Royalty Interest	—	—	—	11	11	—	—	—	(5)	(5)
Purchased Gas	—	—	—	1	1	—	—	—	1	1
Exploration and Other Costs	—	—	—	7	7	—	—	—	1	1
Other Corporate Expenses	—	—	—	16	16	—	—	—	(4)	(4)
Interest Expense	—	—	—	1	1	—	—	—	(1)	(1)
Total Cost	64	35	30	50	179	(8)	(10)	3	(9)	(24)
Earnings Before Income Tax	$31	$(3)	$6	$(22)	$12	$(16)	$3	$(6)	$31	$12

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COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $31 million to total Company earnings before income tax for the three months ended September 30, 2012 compared to $47 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas CBM sales volumes (in billion cubic feet)	21.7	23.3	(1.6)	(6.9)%
Average CBM sales price per thousand cubic feet sold	$4.36	$5.04	$(0.68)	(13.5)%
Average CBM lifting costs per thousand cubic feet sold	0.41	0.41	—	— %
Average CBM ad valorem, severance, and other taxes per thousand cubic feet sold	0.11	0.13	(0.02)	(15.4)%
Average CBM gathering costs per thousand cubic feet sold	1.26	1.06	0.20	18.9 %
Average CBM direct administrative, selling & other costs per thousand cubic feet sold	0.11	0.33	(0.22)	(66.7)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	1.03	1.10	(0.07)	(6.4)%
Total Average CBM costs per thousand cubic feet sold	2.92	3.03	(0.11)	(3.6)%
Average Margin for CBM	$1.44	$2.01	$(0.57)	(28.4)%

CBM sales revenues were $95 million for the three months ended September 30, 2012 compared to $119 million for the three months ended September 30, 2011. The $24 million decrease was primarily due to a 13.5% decrease in average sales price per thousand cubic feet sold, as well as a 6.9% decrease in average volumes sold. The decrease in CBM average sales price is the result of lower general market prices for natural gas, offset, in part, by various gas swap transactions maturing in each period. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 11.4 billion cubic feet of produced CBM gas sales volumes for the three months ended September 30, 2012 at an average price of $5.34 per thousand cubic feet. For the three months ended September 30, 2011, these financial hedges represented 16.6 billion cubic feet at an average price of $5.27 per thousand cubic feet. CBM sales volumes decreased 1.6 billion cubic feet for the three months ended September 30, 2012 compared to the 2011 period primarily due to normal well declines without a corresponding increase in wells drilled and the Buchanan Mine idling, as previously discussed. Currently, the focus of the gas division is to develop its Marcellus and Utica acreage. At September 30, 2012, there were 4,493 gross CBM wells in production. At September 30, 2011, there were 4,397 gross CBM wells in production. Total costs for the CBM segment were $64 million for the three months ended September 30, 2012 compared to $72 million for the three months ended September 30, 2011. Lower costs in the period-to-period comparison were primarily related to lower unit costs as discussed below.

CBM lifting costs were $9 million in the three months ended September 30, 2012 compared to $10 million in the three months ended September 30, 2011. The $1 million decrease was due to lower road maintenance and lower contractor services in the period-to-period comparison. The average CBM lifting unit costs remained consistent in the period-to-period comparison.

CBM ad valorem, severance and other taxes were $2 million in the three months ended September 30, 2012 compared to $3 million in the three months ended September 30, 2011. The decrease in total dollars and unit costs was primarily due to reduced severance tax expense caused by lower average gas sales prices during 2012.

CBM gathering costs were $27 million for the three months ended September 30, 2012 compared to $25 million for the three months ended September 30, 2011. The $2 million increase and $0.20 increase in average per unit costs were due to increased power charges and increased pipeline maintenance. Also, the reduced sales volumes negatively impacted unit costs.

CBM direct administrative, selling & other costs for the CBM segment were $3 million for the three months ended September 30, 2012 compared to $8 million for the three months ended September 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The decrease in direct administrative, selling & other costs was primarily due to reduced direct administrative labor and CBM volumes representing a smaller proportion of total natural gas volumes. Depreciation, depletion and amortization attributable to the CBM segment was $23 million for the three months ended September 30, 2012 compared to $26 million for the three months ended September 30, 2011. There was approximately $15 million, or $0.68 per unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a unit-of-production method of depreciation for the three months ended September 30, 2012. The production portion of depreciation, depletion and amortization was $18 million, or $0.77 per unit-of-production for the three months ended September 30, 2011. The unit-of-production rates are generally calculated using the net book value of assets divided by either proved or proved developed reserves. There was approximately $8 million, or $0.35 average per unit cost of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight line basis in the three months ended September 30, 2012. There was $8 million, or $0.33 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended September 30, 2011.

SHALLOW OIL AND GAS SEGMENT

The Shallow Oil and Gas segment had a loss before income tax of $3 million in the three months ended September 30, 2012 compared to a loss before income tax of $6 million in the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas Shallow Oil and Gas sales volumes (in billion cubic feet)	7.0	7.8	(0.8)	(10.3)%
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.59	$4.98	$(0.39)	(7.8)%
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	1.44	1.91	(0.47)	(24.6)%
Average Shallow Oil and Gas ad valorem, severance, and other taxes per thousand cubic feet sold	0.37	0.31	0.06	19.4%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	0.87	1.00	(0.13)	(13.0)%
Average Shallow Oil and Gas direct administrative, selling & other costs per thousand cubic feet sold	0.35	0.63	(0.28)	(44.4)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	2.05	1.94	0.11	5.7%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	5.08	5.79	(0.71)	(12.3)%
Average Margin for Shallow Oil and Gas	$(0.49)	$(0.81)	$0.32	(39.5)%

Shallow Oil and Gas sales revenues were $32 million for the three months ended September 30, 2012 compared to $39 million for the three months ended September 30, 2011. The $7 million decrease was primarily due to the 7.8% decrease in average sales price per thousand cubic feet sold. Shallow Oil and Gas sales volumes also decreased 10.3% for the three months ended September 30, 2012 compared to the 2011 period primarily due to normal well declines without a corresponding increase in wells drilled. Currently, the focus of the gas division is to develop its Marcellus and Utica acreage. Average sales price decreased primarily due to lower general market prices of natural gas in the period-to-period comparison. This decrease was offset, in part, by the result of various gas swap transactions that matured in the three months ended September 30, 2012. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 4.9 billion cubic feet of produced Shallow Oil and Gas gas sales volumes for the three months ended September 30, 2012 at an average price of $5.23 per thousand cubic feet. In the three months ended September 30, 2011, these financial hedges represented 3.9 billion cubic feet at an average price of $4.94 per thousand cubic feet. At September 30, 2012, there were 9,936 gross Shallow Oil and Gas wells in production. At September 30, 2011, there were 10,015 gross Shallow Oil and Gas wells in production.

Total costs for the Shallow Oil and Gas segment were $35 million for the three months ended September 30, 2012 compared to $45 million for the three months ended September 30, 2011.

Shallow Oil and Gas lifting costs were $10 million for the three months ended September 30, 2012 compared to $15 million for three months ended September 30, 2011. Lifting costs per unit decreased $0.47 due to lower well tending costs, lower water disposal costs, lower road maintenance costs and lower costs associated with non-operated wells. These decreases were offset, in part, by lower volumes sold which negatively impacted unit costs.
Shallow Oil and Gas ad valorem, severance and other taxes were $2 million for the three months ended September 30, 2012 and 2011. The increase in average unit costs was primarily due to lower gas volumes sold in the period-to-period comparison.
Shallow Oil and Gas gathering costs were $6 million for the three months ended September 30, 2012 compared to $8 million for the three months ended September 30, 2011. Shallow Oil and Gas gathering average unit costs decreased primarily as a result of lower compressor maintenance charges, lower firm transportation charges, lower power charges, offset, in part, by lower volumes sold.
Shallow Oil and Gas direct administrative, selling & other costs were $3 million for the three months ended September 30, 2012 compared to $5 million for the three months ended September 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The $2 million decrease in the period-to-period comparison is due to reduced direct administrative labor and Shallow Oil and Gas volumes representing a smaller proportion of total natural gas volumes.
Depreciation, depletion and amortization costs were $14 million for the three months ended September 30, 2012 compared to $15 million for the three months ended September 30, 2011. There was approximately $12 million, or $1.79 per unit-of production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended September 30, 2012. There was approximately $13 million, or $1.72 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended September 30, 2011. The rate is calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $2 million, or $0.26 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended September 30, 2012. There was $2 million, or $0.22 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended September 30, 2011.

MARCELLUS GAS SEGMENT
The Marcellus segment contributed $6 million to the total Company earnings before income tax for the three months ended September 30, 2012 compared to $12 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,					
	2012	2011	Variance		Percent Change	
Produced Gas Marcellus sales volumes (in billion cubic feet)	10.1	8.7	1.4		16.1	%
Average Marcellus sales price per thousand cubic feet sold	$3.58	$4.48	$(0.90	)	(20.1	)%
Average Marcellus lifting costs per thousand cubic feet sold	0.32	0.65	(0.33	)	(50.8	)%
Average Marcellus ad valorem, severance, and other taxes per thousand cubic feet sold	0.12	0.05	0.07		140.0	%
Average Marcellus gathering costs per thousand cubic feet sold	0.68	0.29	0.39		134.5	%
	0.55	0.34	0.21		61.8	%

Average Marcellus direct administrative, selling & other costs per thousand cubic feet sold				
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	1.28	1.72	(0.44)	(25.6)%
Total Average Marcellus costs per thousand cubic feet sold	2.95	3.05	(0.10)	(3.3)%
Average Margin for Marcellus	$0.63	$1.43	$(0.80)	(55.9)%

The Marcellus segment sales revenues were $36 million for the three months ended September 30, 2012 compared to $39 million for the three months ended September 30, 2011. The decrease in Marcellus average sales price was the result of lower general market prices, offset, in part, by various gas swap transactions that matured in each period. These gas swap transactions

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qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 3.0 billion cubic feet of produced Marcellus gas sales volumes for the three months ended September 30, 2012 at an average price of $4.97 per thousand cubic feet. These financial hedges represented 3.4 billion cubic feet of produced Marcellus gas sales volumes for the three months ended September 30, 2011 at an average price of $4.61 per thousand cubic feet. The increased sales volumes are primarily due to additional wells coming on-line from our on-going drilling program, offset, in part, by a decrease of 4.5 billion net cubic feet of production related to the 2011 Antero divestiture and 2011 Noble joint venture. At September 30, 2012, there were 194 gross Marcellus Shale wells in production. At September 30, 2011, there were 122 gross Marcellus Shale wells in production.

Marcellus lifting costs were $3 million for the three months ended September 30, 2012 compared to $6 million for the three months ended September 30, 2011. Lifting costs per unit decreased $0.33 per thousand cubic feet sold due to lower well tending costs and well service costs in the period-to-period comparison, combined with higher volumes sold.

Marcellus ad valorem, severance and other taxes were $1 million in the period ended September 30, 2012 compared to less than $1 million in the period ended September 30, 2011. The increase in the current period per unit cost is primarily due to new legislation passed in the state of Pennsylvania (Act 13 of 2012, House Bill 1950). This legislation permits Pennsylvania counties to impose annual fees on unconventional gas wells located within Pennsylvania. The impact on unit costs of this increase was offset, in part, by higher volumes sold.

Marcellus gathering costs were $7 million for the three months ended September 30, 2012 compared to $3 million for the three months ended September 30, 2011. Average Marcellus gathering unit costs increased due to higher firm transportation costs and gathering costs associated with 1.4 billion cubic feet of additional volumes sold.

Marcellus direct administrative, selling & other costs related to the Marcellus gas segment were $6 million for the three months ended September 30, 2012 compared to $3 million for the three months ended September 30, 2011. Direct administrative, selling & other costs attributable to the total gas division are allocated to the individual gas segments based on a combination of production and employee counts. The increase in direct administrative, selling & other costs was primarily due to increased direct administrative labor and Marcellus volumes representing a higher proportion of total natural gas volumes.

Depreciation, depletion and amortization costs were $13 million for the three months ended September 30, 2012 compared to $15 million for the three months ended September 30, 2011. There was approximately $12 million, or $1.22 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended September 30, 2012. There was approximately $10 million, or $1.12 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended September 30, 2011. The rate is calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. Additionally, there was $1 million, or $0.06 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis in the three months ended September 30, 2012. There was $5 million, or $0.60 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis in the three months ended September 30, 2011. The decrease in Marcellus gathering and other equipment depreciation, depletion and amortization relates to the sale of assets to CONE Gathering LLC (CONE), a 50% owned affiliate. See Note 2 - Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional information.

OTHER GAS SEGMENT

The other gas segment includes activity not assigned to the CBM, Shallow Oil and Gas or Marcellus gas segments. This segment includes gas general and administrative costs, purchased gas activity, gas royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific gas segment.

Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee and the Utica Shale in Ohio. Revenue from these operations were approximately $2 million for the three months ended September 30, 2012 and 2011. Total costs related to these other sales were $4 million in the 2012 period and $2 million in the 2011 period. The increase in costs is due to various transactions which occurred throughout both periods, none of which are individually material. A per unit analysis of the other operating costs in the Chattanooga Shale and the Utica Shale is not meaningful due to the low volumes produced in the period-to-period analysis.

Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas sales revenue was $13 million for the three months ended September 30, 2012 compared to $17 million for the three months ended September 30, 2011. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	4.8	3.9	0.9	23.1 %
Average Sales Price Per thousand cubic feet	$2.67	$4.34	$(1.67)	(38.5)%

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $1 million for both the three months ended September 30, 2012 and 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	0.3	0.3	—	— %
Average Sales Price Per thousand cubic feet	$3.29	$4.43	$(1.14)	(25.7)%

Other income was $12 million for the three months ended September 30, 2012 compared to a loss of $14 million for the three months ended September 30, 2011. The $26 million increase was due primarily to a $58 million loss on the Noble transaction during 2011, partially offset by a gain on the sale of Antero overriding royalty interest of $41 million during 2011. Additionally, the increase is due to $8 million of additional interest income relating to the notes receivable from the Noble joint venture transaction. The additional $1 million increase is due to various other transactions that occurred throughout both periods, none of which are individually material.

General and administrative costs are allocated to the total gas segment based on percentage of total revenue and percentage of total projected capital expenditures. Costs were $10 million for the three months ended September 30, 2012 compared to $13 million for the three months ended September 30, 2011. Refer to the discussion of total general and administrative costs contained in the section "Net Income" of this quarterly report for detailed cost explanations.

Royalty interest gas costs represent the costs related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas costs were $11 million for the three months ended September 30, 2012 compared to $16 million for the three months ended September 30, 2011. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	4.8	3.9	0.9	23.1 %
Average Cost Per thousand cubic feet sold	$2.18	$3.92	$(1.74)	(44.4)%

Purchased gas volumes represent volumes of gas purchased from third-party producers that we sell. Purchased gas volumes also reflect the impact of pipeline imbalances. The higher average cost per thousand cubic feet is due to overall price changes and contractual differences among customers in the period-to-period comparison. Purchased gas costs were $1 million for the three months ended September 30, 2012 compared to less than $1 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	0.2	0.2	—	— %

Average Cost Per thousand cubic feet sold	$3.04	$1.62	$1.42	87.7 %

Exploration and other costs were $7 million for the three months ended September 30, 2012 compared to $6 million for the three months ended September 30, 2011.

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	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Lease Expiration Costs	$4	$4	$—	— %
Dry Hole Costs	—	2	(2)	(100.0)%
Exploration	3	—	3	100.0 %
Total Exploration and Other Costs	$7	$6	$1	16.7 %

- Lease Expiration costs were consistent in period-to-period comparison. Lease expiration costs relate to locations where CONSOL Energy allowed primary term leases to expire.
- Dry Hole Costs decreased $2 million due to additional dry hole wells in the 2011 period. There were no dry hole costs incurred during the three months ended September 30, 2012.
- Exploration expenses increased $3 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses were $16 million for the three months ended September 30, 2012 compared to $20 million for the three months ended September 30, 2011. The $4 million decrease in the period-to-period comparison was made up of the following items:

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Contract Buyout	$—	$3	$(3)	(100.0)%
Short-term incentive compensation	5	6	(1)	(16.7)%
Stock-based compensation	4	5	(1)	(20.0)%
Unutilized firm transportation	4	4	—	— %
Bank fees	2	2	—	— %
Other	1	—	1	100.0 %
Total Other Corporate Expenses	$16	$20	$(4)	(20.0)%

- Contract Buyout represents the cancellation of a drilling arrangement with a third-party well driller.
- Short-term incentive compensation decreased $1 million in the period-to-period comparison. The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for safety, environmental compliance, production, and unit costs.
- Stock-based compensation decreased $1 million in the period-to-period comparison due to various activity in share-based compensation programs, none of which were individually material.
- Unutilized firm transportation costs represent excess pipeline transportation capacity that the gas division obtained to enable gas production to flow on an uninterrupted basis as sales volumes increase. These costs remained consistent in the period-to-period comparison.
- Bank fees remained consistent in the period-to-period comparison.
- Other expenses increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense related to the other gas segment was $1 million for the three months ended September 30, 2012 compared to $2 million for the three months ended September 30, 2011. The $1 million decrease in interest expense comparison is primarily due to lower average borrowings during the period on the CNX Gas Credit Facility.

OTHER SEGMENT ANALYSIS for the three months ended September 30, 2012 compared to the three months ended September 30, 2011:

The other segment includes activity from the sales of industrial supplies, the transportation operations and various other corporate activities that are not allocated to the coal or gas segments. The other segment had a loss before income tax of $47 million for the three months ended September 30, 2012 compared to a loss before income tax of $68 million for the three months ended September 30, 2011. The other segment also included total company income tax benefit of ($20) million for the three months ended September 30, 2012 compared to expense of $33 million for the three months ended September 30, 2011.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Sales—Outside	$88	$88	$—	— %
Other Income	6	7	(1)	(14.3)%
Total Revenue	94	95	(1)	(1.1)%
Cost of Goods Sold and Other Charges	78	98	(20)	(20.4)%
Depreciation, Depletion & Amortization	6	5	1	20.0 %
Taxes Other Than Income Tax	3	3	—	— %
Interest Expense	54	57	(3)	(5.3)%
Total Costs	141	163	(22)	(13.5)%
Loss Before Income Tax	(47)	(68)	21	30.9 %
Income Tax	(20)	33	(53)	(160.6)%
Net Loss	$(27)	$(101)	$74	73.3 %

Industrial supplies:

Total revenue from industrial supplies was $59 million for the three months ended September 30, 2012 compared to $62 million for the three months ended September 30, 2011. The decrease was primarily related to lower sales volumes.

Total costs related to industrial supply sales were $56 million for the three months ended September 30, 2012 compared to $59 million for the three months ended September 30, 2011. The decrease of $3 million was primarily related to lower sales volumes and various changes in inventory costs, none of which were individually material.

Transportation operations:

Total revenue from transportation operations was $31 million for the three months ended September 30, 2012 compared to $29 million for the three months ended September 30, 2011. The increase of $2 million was primarily attributable to higher per ton thru-put rates at the CNX Marine Terminal.

Total costs related to the transportation operations were $23 million for the three months ended September 30, 2012 and $22 million for the three months ended September 30, 2011. The increase was due to various items in both periods, none of which were individually material.

Miscellaneous other:

Additional other income was $4 million for both the three months ended September 30, 2012 and 2011. The income is primarily related to the earnings from our equity affiliates that are included in the other segment.

Other corporate costs in the other segment include interest expense, bank fees and various other miscellaneous corporate charges. Total other costs were $62 million for the three months ended September 30, 2012 compared to $82 million for the three months ended September 30, 2011. Other corporate costs decreased due to the following items:

	For the Three Months Ended September 30,		
	2012	2011	Variance
Transaction and financing fees	$—	$15	$(15)
Interest Expense	53	57	(4)
Bank Fees	3	6	(3)
Evaluation fees for non-core asset dispositions and other legal charges	3	2	1
Other	3	2	1
	$62	$82	$(20)

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- On April 11, 2011, CONSOL Energy redeemed all of its outstanding $250 million, 7.875% senior secured notes due March 1, 2012 in accordance with the terms of the indenture governing these notes. The loss on extinguishment of debt was $15 million, which primarily represented the interest that would have been paid on these notes if held to maturity.
- Interest expense decreased $4 million primarily due to an increase in capitalized interest due to higher capital expenditures for major construction projects in the current period. These decreases were offset by an increase in uncertain tax positions interest expense.
- Bank fees decreased $3 million due to lower borrowings on the revolving credit facilities in the period-to-period comparison.
- Evaluation fees for non-core asset dispositions and other legal charges increased $1 million in the period-to-period comparison due to various corporate initiatives that were completed in 2011.
- Other corporate items increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 63.4% in the three months ended September 30, 2012 compared to 16.5% in the three months ended September 30, 2011. The increase in the effective tax rate for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011 was attributable to discrete items reflected in the current year related to the accrual to return adjustment, offset in part, by the Canadian Revenue Agency adjustments. The effective tax rate was also impacted by the relationship between the pre-tax earnings and percentage depletion. See Note 5—Income Taxes of the Notes to the Condensed Consolidated Financial Statements of this Form 10-Q for additional information.

	For the Three Months Ended September 30,			
	2012	2011	Variance	Percent Change
Total Company Earnings Before Income Tax	$(31)	$200	$(231)	(115.5)%
Income Tax Expense	$(20)	$33	$(53)	(160.6)%
Effective Income Tax Rate	63.4%	16.5%	46.9%	

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Results of Operations
Nine Months Ended September 30, 2012 Compared with Nine Months Ended September 30, 2011
Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $239 million, or $1.04 per diluted share, for the nine months ended September 30, 2012. Net income attributable to CONSOL Energy shareholders was $437 million, or $1.91 per diluted share, for the nine months ended September 30, 2011.
The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $419 million of earnings before income tax for the nine months ended September 30, 2012 compared to $719 million for the nine months ended September 30, 2011. The total coal division sold 41.7 million tons of coal produced from CONSOL Energy mines for the nine months ended September 30, 2012 compared to 47.2 million tons for the nine months ended September 30, 2011.
The average sales price and total costs per ton for all active coal operations were as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per ton sold	$ 67.35	$ 72.48	$ (5.13)	(7.1)%
Average Cost of Goods Sold per ton	54.09	50.07	4.02	8.0 %
Margin per ton sold	$ 13.26	$ 22.41	$ (9.15)	(40.8)%

The lower average sales price per ton sold reflects a decrease in the global metallurgical coal markets, slightly offset by higher thermal coal average prices as a result of several successful re-negotiations of domestic thermal contracts where pricing took effect on January 1, 2012. The coal division priced 8.8 million tons on the export market at an average sales price of $76.24 for the nine months ended September 30, 2012 compared to 8.6 million tons at an average price of $124.54 per ton for the nine months ended September 30, 2011. All other tons were sold on the domestic market. The decreased sales tonnage is due to decreased coal demand in both thermal and metallurgical markets and curtailed shipments due to the Bailey Belt incident discussed previously.

Changes in the average cost of goods sold per ton were primarily related to the following items:

- Average cost of goods sold per ton sold increased due to fewer tons sold. Fixed costs are allocated over fewer sales tons, resulting in higher unit costs.
- The idle longwalls at the Blacksville Mine and the Buchanan Mine during March and April 2012 resulted in an increase in unit costs of approximately $1.32 per ton as the fixed costs were allocated over fewer tons.
- Average operating supplies and maintenance costs per ton sold increased due to additional equipment maintenance, timing of major equipment overhaul costs, increased fuels and lubricants and use of pumpable cribs for roof support.
- Average labor and labor related expenses per ton sold increased primarily as a result of the impact of the UMWA contract wage increases, offset, in part, by lower overtime.
- Average depreciation, depletion and amortization per ton sold increased due to additional assets placed into service after the 2011 period.
- Average retirement and disability costs per ton decreased due to the improvement in other postretirement benefits discussed in the long-term liabilities section below.

The total gas division includes CBM, Shallow Oil and Gas, Marcellus and other gas. The total gas division contributed $25 million of earnings before income tax for the nine months ended September 30, 2012 compared to $53 million for the nine months ended September 30, 2011. Total gas production was 114.5 billion cubic feet for the nine months ended September 30, 2012 compared to 113.8 billion cubic feet for the nine months ended September 30, 2011. Total gas production increased primarily as a result of the on-going drilling program, offset, in part, by a 10.7 billion cubic feet decrease in production related to both the 2011 divestiture of Antero Resources Appalachian Corp. (Antero) and the 2011 Noble Joint Venture. Production also decreased due to the Buchanan Mine idling as previously discussed.

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The average sales price and total costs for all active gas operations were as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	4.14	4.97	(0.83)	(16.7)%
Average Costs per thousand cubic feet sold	3.37	3.55	(0.18)	(5.1)%
Margin per thousand cubic feet sold	0.77	1.42	(0.65)	(45.8)%

Total gas division outside sales revenues were $475 million for the nine months ended September 30, 2012 compared to $566 million for the nine months ended September 30, 2011. The decrease was primarily due to the 16.7% reduction in average price per thousand cubic feet sold, offset, in part, by the 0.6% increase in volumes sold. The decrease in average sales price is the result of of the decline in general market prices, partially offset by various gas swap transactions that occurred throughout both periods. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 57.5 billion cubic feet of our produced gas sales volumes for the nine months ended September 30, 2012 at an average price of $5.25 per thousand cubic feet. These financial hedges represented 60.1 billion cubic feet of our produced gas sales volumes for the nine months ended September 30, 2011 at an average price of $5.23 per thousand cubic feet.

Changes in the average cost per thousand cubic feet of gas sold were primarily related to the following items:

- Higher volumes in the period-to-period comparison due to the on-going drilling program, offset, in part, by 10.7 billion cubic feet divested in the 2011 Noble and 2011 Antero transactions resulted in lower average costs per thousand cubic feet sold. Fixed costs are allocated over increased volumes, resulting in lower unit costs.
- Lower units-of-production depreciation, depletion and amortization rates for producing properties. These rates were generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. Increased proved and proved developed reserves relative to the net book value of the producing assets resulted in a lower units-of-production rate.
- Lower direct administrative, selling and other costs per thousand cubic feet sold due to increased sales volumes and decreased actual dollars as a result of lower direct administrative labor and other costs.
- Gathering costs increased in the period-to-period comparison due to higher transportation charges.

The other segment includes industrial supplies activity, terminal, river and dock service activity, income taxes and other business activities not assigned to the coal or gas segment.

In the nine months ended September 30, 2012, management decided that it would no longer consider general and administrative costs on a segment by segment basis as a factor in their decision making process. These decisions include allocation of capital and individual segment profit performance results. Management did conclude that general and administrative costs would continue to be considered in results at the divisional level (total coal and total gas). In order to present financial information in a manner consistent with internal management's evaluations, the prior periods general and administrative costs have been reclassified to reflect information consistent with the current year's presentation. The total divisional results have not changed. Individual segment results within the division have been recast to reflect costs excluding general and administrative. General and administrative costs are excluded from the coal and gas unit costs above. As in the prior periods, general and administrative costs are allocated between divisions (Coal, Gas, Other) based primarily on percentage of total revenue and percentage of total projected capital expenditures. The total general and administrative costs were made up of the following items:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Employee wages and related expenses	$45	$50	$(5)	(10.0)%
Consulting and professional services	24	27	(3)	(11.1)%

Contributions	2	6	(4)	(66.7)%
Miscellaneous	25	27	(2)	(7.4)%
Total Company General and Administrative Expenses	$96	$110	$(14)	(12.7)%

Total Company General and Administrative Expenses changed due to the following:

- Employee wages and related expenses decreased $5 million primarily attributable to lower salary OPEB expenses in the period-to-period comparison. The lower expenses relate to changes in the discount rates and other assumptions, and a modification to the benefit plan for certain salaried employees.
- Consulting and professional services decreased $3 million in the period-to-period comparison due to a reduction in CONSOL Energy's advertising and promotion campaign.
- Contributions decreased $4 million in the period-to-period comparison due to various transactions, none of which were individually material.
- Miscellaneous general and administrative expenses decreased $2 million in the period-to-period comparison due to various transactions, none of which were individually material.

Total Company long-term liabilities, such as OPEB, the salary retirement plan, workers' compensation and long-term disability are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Total CONSOL Energy expense related to our actuarial liabilities was $195 million for the nine months ended September 30, 2012 compared to $249 million for the nine months ended September 30, 2011. The decrease of $54 million for total CONSOL Energy expense was primarily due to a decrease in the discount rate assumptions used to calculate expense for benefit plans at the measurement date, which is December 31. Additionally, a part of the decrease was due to a plan modification for the salaried OPEB plan which required a remeasurement at March 31, 2012. See Note 3—Components of Pension and Other Postretirement Benefit Plans Net Periodic Benefit Costs and Note 4—Components of Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation Net Periodic Benefit Costs in the Notes to the Unaudited Consolidated Financial Statements for additional detail of the total Company expense decrease.

TOTAL COAL SEGMENT ANALYSIS for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011:

The coal segment contributed $419 million of earnings before income tax in the nine months ended September 30, 2012 compared to $719 million in the nine months ended September 30, 2011. Variances by the individual coal segments are discussed below.

	For the Nine Months Ended September 30, 2012					Difference to Nine Months Ended September 30, 2011				
	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$2,228	$180	$403	$6	$2,817	$(87)	$(99)	$(421)	$(16)	$(623)
Purchased Coal	—	—	—	13	13	—	—	—	(24)	(24)
Total Outside Sales	2,228	180	403	19	2,830	(87)	(99)	(421)	(40)	(647)
Freight Revenue	—	—	—	126	126	—	—	—	(30)	(30)
Other Income	1	7	—	225	233	(4)	(2)	—	172	166
Total Revenue and Other Income	2,229	187	403	370	3,189	(91)	(101)	(421)	102	(511)
Costs and Expenses:										
Beginning inventory costs	89	2	16	—	107	(9)	2	6	(1)	(2)
Total direct costs	1,160	84	160	138	1,542	28	(18)	(5)	22	27
Total royalty/production taxes	152	9	25	2	188	(3)	(2)	(25)	(2)	(32)
Total direct services to operations	185	19	17	210	431	(10)	(4)	1	5	(8)
Total retirement and disability	133	9	23	15	180	(41)	(6)	(8)	3	(52)
Depreciation, depletion and amortization	225	19	30	23	297	(1)	(3)	3	(103)	(104)
Ending inventory costs	(67)	—	(33)	(1)	(101)	15	—	(24)	(1)	(10)
Total Costs and Expenses	1,877	142	238	387	2,644	(21)	(31)	(52)	(77)	(181)
Freight Expense	—	—	—	126	126	—	—	—	(30)	(30)
Total Costs	1,877	142	238	513	2,770	(21)	(31)	(52)	(107)	(211)
Earnings (Loss) Before Income Taxes	$352	$45	$165	$(143)	$419	$(70)	$(70)	$(369)	$209	$(300)

THERMAL COAL SEGMENT

The thermal coal segment contributed $352 million to total Company earnings before income tax for the nine months ended September 30, 2012 compared to $422 million for the nine months ended September 30, 2011. The thermal coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced Thermal Tons Sold (in millions)	36.1	39.3	(3.2)	(8.1)%
Average Sales Price Per Thermal Ton Sold	$61.79	$58.88	$2.91	4.9%
Beginning Inventory Costs Per Thermal Ton	$58.32	$51.73	$6.59	12.7%
Total Direct Operating Costs Per Thermal Ton Produced	$32.39	$28.98	$3.41	11.8%
Total Royalty/Production Taxes Per Thermal Ton Produced	4.25	3.98	0.27	6.8%
Total Direct Services to Operations Per Thermal Ton Produced	5.18	5.00	0.18	3.6%
Total Retirement and Disability Per Thermal Ton Produced	3.71	4.46	(0.75)	(16.8)%
Total Depreciation, Depletion and Amortization Costs Per Thermal Ton Produced	6.28	5.80	0.48	8.3%
Total Production Costs Per Thermal Ton Produced	$51.81	$48.22	$3.59	7.4%
Ending Inventory Costs Per Thermal Ton	$51.55	$52.89	$(1.34)	(2.5)%
Total Costs Per Thermal Ton Sold	$52.06	$48.28	$3.78	7.8%
Average Margin Per Thermal Ton Sold	$9.73	$10.60	$(0.87)	(8.2)%

Thermal coal revenue was $2,228 million for the nine months ended September 30, 2012 compared to $2,315 million for the nine months ended September 30, 2011. The $87 million decrease was attributable to a 3.2 million reduction in tons sold, offset, in part, by a $2.91 per ton higher average sales prices. The sales ton decrease was primarily due to weak market conditions and the July 27, 2012 structural failure of the above-ground conveyor system at the Bailey Preparation Plant. The incident curtailed shipments of production from both Bailey Mine and the Enlow Fork Mine during the reconstruction period, as previously discussed. The higher average thermal coal sales price in the 2012 period was the result of several successful renegotiations of domestic thermal contracts whose pricing took effect on January 1, 2012. Higher average thermal coal sale prices per ton were offset, in part, as a result of the change in mix of coal sold as a result of the Bailey Belt incident, as previously discussed. Also, 4.1 million tons of thermal coal were priced on the export market at an average sales price of $58.10 per ton for the nine months ended September 30, 2012 compared to 1.8 million tons at an average price of $68.13 per ton for the nine months ended September 30, 2011. Other income attributable to the thermal coal segment represents earnings from our equity affiliates that operate thermal coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Total cost of goods sold are comprised of changes in thermal coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for thermal coal was $1,877 million for the nine months ended September 30, 2012, or $21 million lower than the $1,898 million for the nine months ended September 30, 2011. Although total cost of goods sold dollars were improved, total costs per ton sold were impaired. Total cost of goods sold for thermal coal was $52.06 per ton in the nine months ended September 30, 2012 compared to $48.28 per ton in the nine months ended September 30, 2011. Average cost of goods sold per ton was impacted by the idling of the Blacksville Mine longwall during March and April 2012. The mine continued to run the continuous miners and complete mine maintenance throughout March and April which negatively impacted year-to-date unit costs by $0.79. The increase in costs of goods sold per thermal ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Direct Operating costs related to the thermal coal segment were $1,160 million in the nine months ended September 30, 2012 compared to $1,132 million in the nine months ended September 30, 2011. Direct operating costs were

$32.39 per ton produced in the current period compared to $28.98 per ton produced in the prior year period. Changes in the average direct operating costs per thermal ton produced were primarily related to the following items:

- Average operating costs per thermal ton produced increased due to fewer tons produced. Fixed costs are allocated over less tons, resulting in higher unit costs.
- The Blacksville No. 2 longwall idling resulted in higher direct operating costs per ton produced. The mine continued to run the continuous miners and perform mine maintenance during the month of April when the longwall was idled for market reasons, which negatively impacted unit costs.
- Labor and related benefits average costs per thermal ton produced increased. This was primarily due to the impact of the wage increases per hour worked related to the United Mine Workers of America (UMWA) collective bargaining agreement in the period-to-period comparison, offset, in part, by fewer overtime hours worked.
- Average operating supplies and maintenance costs per ton increased due to additional maintenance and equipment overhaul costs and additional contractor labor, combined with lower tons produced. Additional maintenance and equipment overhaul costs are related to additional equipment being service in the current year-to-date period. Additional contractor labor costs resulted from additional underground hourly contractors utilized as well as additional security contractor costs in the current year.
- There were no significant changes in various other unit costs individually or in total.

Royalties and production taxes decreased $3 million to $152 million in the current year-to-date period. Average cost per thermal ton produced increased $0.27 per ton due to lower production volumes, and higher average sales prices which is the basis for most production taxes.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The cost of these support services were $185 million in the current year-to-date period compared to $195 million in the prior year-to-date period. Direct services to the operations were $5.18 per ton in the current period compared to $5.00 per ton in the prior year-to-date period. Changes in the average direct service to operations cost per thermal ton produced were primarily related to the following items:

- Average direct service costs to operations were impaired due to lower tons produced in the period-to-period comparison.
- Permitting and compliance costs have increased due to increased stream monitoring expenses, increased compliance work related to ponds and ditches, and additional permits for water discharge pipelines.
- Selling expense decreased in the period-to-period comparison due to fewer tons being sold under contracts that require commissions.

Retirement and disability costs are comprised of the expenses related to the Company's long-term liabilities, such as other post-retirement benefits (OPEB), the salary retirement plan, workers' compensation, coal workers' pneumoconiosis (CWP) and long-term disability. These liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. The average retirement and disability costs attributable to the thermal coal segment were $133 million for the nine months ended September 30, 2012 compared to $174 million for the nine months ended September 30, 2011. The decrease in the thermal coal retirement and disability costs was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. These improvements were offset, in part, by the reduction in production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the thermal coal segment was $225 million for the nine months ended September 30, 2012 compared to $226 million for the nine months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per thermal ton produced were higher in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a

straight-line basis.
Changes in thermal coal inventory volumes and carrying value resulted in $22 million of cost of goods sold in the nine months ended September 30, 2012 compared to $16 million in the nine months ended September 30, 2011. Thermal coal inventory was 1.3 million tons at September 30, 2012 compared to 1.6 million tons at September 30, 2011.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $45 million to total Company earnings before income tax for the nine months ended September 30, 2012 compared to $115 million for the nine months ended September 30, 2011. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced High Vol Met Tons Sold (in millions)	2.9	3.5	(0.6)	(17.1)%
Average Sales Price Per High Vol Met Ton Sold	$62.64	$78.75	$(16.11)	(20.5)%
Beginning Inventory Costs Per High Vol Met Ton	$63.50	$—	$63.50	— %
Total Direct Operating Costs Per High Vol Met Ton Produced	$29.30	$28.67	$0.63	2.2 %
Total Royalty/Production Taxes Per High Vol Met Ton Produced	3.15	3.10	0.05	1.6 %
Total Direct Services to Operations Per High Vol Met Ton Produced	6.42	6.43	(0.01)	(0.2)%
Total Retirement and Disability Per High Vol Met Ton Produced	3.15	4.28	(1.13)	(26.4)%
Total Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Produced	6.54	6.25	0.29	4.6 %
Total Production Costs Per High Vol Met Ton Produced	$48.56	$48.73	$(0.17)	(0.3)%
Ending Inventory Costs Per High Vol Met Ton	$—	$—	$—	— %
Total Costs Per High Vol Met Ton Sold	$49.44	$48.73	$0.71	1.5 %
Margin Per High Vol Met Ton Sold	$13.20	$30.02	$(16.82)	(56.0)%

High volatile metallurgical coal revenue was $180 million for the nine months ended September 30, 2012 compared to $279 million for the nine months ended September 30, 2011. Average sales prices for high volatile metallurgical coal decreased $16.11 per ton in a period-to-period comparison due to a weakening in global metallurgical coal demand. CONSOL Energy priced 2.5 million tons of high volatile metallurgical coal in the export market at an average sales price of $60.10 per ton for the nine months ended September 30, 2012 compared to 3.3 million tons at an average price of $78.21 per ton for the nine months ended September 30, 2011. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in high volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for high volatile metallurgical coal was $142 million for the nine months ended September 30, 2012, or $31 million lower than the $173 million for the nine months ended September 30, 2011. Total cost of goods sold for high volatile metallurgical coal was $49.44 per ton in the nine months ended September 30, 2012 compared to $48.73 per ton in the nine months ended September 30, 2011. The increase in cost of goods sold per high volatile metallurgical ton was due to the items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Direct Operating costs related to the high volatile metallurgical coal segment were $84 million in the nine months ended September 30, 2012 compared to $102 million in the nine months ended September 30, 2011. Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and due to cost control measures that were implemented. Although improved $18 million, the cost improvements did not completely offset the impact of reduced production on unit costs. Direct operating costs were $29.30 per ton produced in the current year-to-date period compared to $28.67 per ton produced in the prior year-to-date period. Changes in the average direct operating costs per high volatile metallurgical ton produced were primarily related to the following items:

- Average operating costs per high volatile metallurgical ton increased due to fewer tons produced. Fixed costs are allocated over less tons, resulting in higher unit costs.

- Mine maintenance and supplies per ton produced increased due to the mix of mines producing tons that were shipped as high volatile metallurgical coal. Mines with higher cost structures produced a larger portion of the high volatile metallurgical coal shipped in the current year-to-date period compared to the prior year-to-date period. This was primarily due to the Bailey belt incident previously discussed.
- Labor and related benefits average costs per high volatile metallurgical ton produced decreased due to less overtime worked, offset, in part, by lower tons produced and higher hourly wage rates.
- Various other unit costs including power and miscellaneous costs did not change significantly individually or in total.

Royalties and production taxes improved $2 million to $9 million in the current year-to-date period compared to $11 million in the prior year-to-date period. The improvement was due to lower volumes and lower average sales prices. Although dollars were lower, unit costs were $0.05 per ton higher. High volatile metallurgical coal royalties and production taxes were $3.15 per ton in the current year-to-date period compared to $3.10 per ton in the prior year-to-date period. Average cost per high volatile metallurgical ton produced increased due to an increase in the tons mined on leased versus owned properties in the year-to-date period-to-period comparison.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for high volatile metallurgical coal were $19 million in the current year-to-date period compared to $23 million in the prior year-to-date period. Lower costs were attributable to fewer tons subject to commission expense, lower direct administrative costs, and lower subsidence costs. Direct services to the operations for high volatile metallurgical coal were $6.42 per ton in the current year-to-date period compared to $6.43 per ton in the prior year-to-date period. Changes in the average direct service to operations cost per ton for high volatile metallurgical coal produced were primarily related to lower dollars spent, offset by lower tons produced.

Retirement and disability costs are comprised of the expenses related to the Company's long-term liabilities, such as other post-retirement benefits (OPEB), the salary retirement plan, workers' compensation, coal workers' pneumoconiosis (CWP) and long-term disability. These liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. The average retirement and disability costs attributable to the high volatile metallurgical coal segment were $9 million for the nine months ended September 30, 2012 compared to $15 million for the nine months ended September 30, 2011. The decrease in the high volatile metallurgical coal retirement and disability costs was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. These improvements were offset, in part, by the reduction in production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $19 million for the nine months ended September 30, 2012 compared to $22 million for the nine months ended September 30, 2011. The decrease was primarily due to lower depletion directly related to lower production volumes. Unit costs per high volatile ton produced were higher in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis.

Changes in high volatile metallurgical coal inventory volumes and carrying value resulted in $2 million of cost of goods sold in the nine months ended September 30, 2012. There were no changes in volumes or carrying value in the nine months ended September 30, 2011. There was no high volatile metallurgical coal inventory at September 30, 2012 or September 30, 2011.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $165 million to total Company earnings before income tax in the nine months ended September 30, 2012 compared to $534 million in the nine months ended September 30, 2011. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Company Produced Low Vol Met Tons Sold (in millions)	2.8	4.3	(1.5)	(34.9)%
Average Sales Price Per Low Vol Met Ton Sold	$143.30	$191.84	$(48.54)	(25.3)%
Beginning Inventory Costs Per Low Vol Met Ton	$67.60	$62.51	$5.09	8.1%
Total Direct Operating Costs Per Low Vol Met Ton Produced	$54.12	$38.67	$15.45	40.0%
Total Royalty/Production Taxes Per Low Vol Met Ton Produced	8.66	11.71	(3.05)	(26.0)%
Total Direct Services to Operations Per Low Vol Met Ton Produced	5.64	3.83	1.81	47.3%
Total Retirement and Disability Per Low Vol Met Ton Produced	7.90	7.24	0.66	9.1%
Total Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Produced	10.10	6.37	3.73	58.6%
Total Production Costs Per Low Vol Met Ton Produced	$86.42	$67.82	$18.60	27.4%
Ending Inventory Costs Per Low Vol Met Ton	$87.32	$67.35	$19.97	29.7%
Total Costs Per Low Vol Met Ton Sold	$84.75	$67.62	$17.13	25.3%
Margin Per Low Vol Met Ton Sold	$58.55	$124.22	$(65.67)	(52.9)%

Low volatile metallurgical coal revenue was $403 million for the nine months ended September 30, 2012 compared to $824 million for the nine months ended September 30, 2011. The $421 million decrease was attributable to a $48.54 per ton lower average sales price. Average sales prices for low volatile metallurgical coal decreased in the period-to-period comparison due to the weakening in global metallurgical coal demand. For the 2012 period, 2.1 million tons of low volatile metallurgical coal was priced on the export market at an average price of $130.56 per ton compared to 3.5 million tons at an average price of $196.79 per ton for the 2011 period. The remaining tons sold in the period-to-period comparison were sold on the domestic market.

Total cost of goods sold are comprised of changes in low volatile metallurgical coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for low volatile metallurgical coal was $238 million for the nine months ended September 30, 2012, or $52 million lower than the $290 million for the nine months ended September 30, 2011. Total cost of goods sold for low volatile metallurgical coal was $84.75 per ton in the nine months ended September 30, 2012 compared to $67.62 per ton in the nine months ended September 30, 2011. The increase in cost of goods sold per low volatile metallurgical ton was due to the following items described below.

Direct Operating costs are comprised of labor, supplies, maintenance, power and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Direct Operating costs related to the low volatile metallurgical coal segment were $160 million in the nine months ended September 30, 2012 compared to $165 million in the nine months ended September 30, 2011. Direct operating costs dollars are improved due to lower tons produced in the period-to-period comparison and cost control measures implemented. Although improved $5 million, the cost improvements did not offset the impact of reduced production on unit costs. Direct operating costs were $54.12 per ton produced in the current year-to-date period compared to $38.67 per ton produced in the prior year-to-date period. Changes in the average direct operating costs per low volatile ton produced were primarily related to the following items:

- The Buchanan longwall was idled during the months of March and April which resulted in $10.59 per ton higher direct operating costs produced. The mine continued to run the continuous miners and perform mine maintenance during the month when the longwall was idled. This negatively impacted unit costs.

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Low volatile metallurgical coal production was 3.0 million tons in the nine months ended September 30, 2012 compared to 4.3 million tons in the nine months ended September 30, 2011. Production was significantly lower in the period-to-period comparison due to the Buchanan Mine being idled in early September 2012. The mine was idled in response to weak market demand for low volatile metallurgical coal. Fixed costs were then spread over fewer tons produced which increased all costs on a per unit basis.

Royalties and production taxes improved $25 million to $25 million in the current year-to-date period compared to $50 million in the prior year-to-date period. Unit costs also improved $3.05 per low volatile metallurgical ton produced to $8.66 per ton in the current year-to-date period compared to $11.71 per ton in the prior year-to-date period. Average cost per low volatile metallurgical ton produced decreased due to lower royalties and lower production taxes. These decreases were related to lower volumes produced and lower average sales prices.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The costs of these support services for low volatile metallurgical coal were $17 million in the current year-to-date period compared to $16 million in the prior year-to-date period. Direct services to the operations for low volatile metallurgical coal were $5.64 per ton in the current year-to-date period compared to $3.83 per ton in the prior year-to-date period. Changes in the average direct service to operations cost per ton for low volatile metallurgical coal produced were primarily related to lower tons of coal produced in the period-to-period comparison.

Retirement and disability costs are comprised of the expenses related to the Company's long-term liabilities, such as other post-retirement benefits (OPEB), the salary retirement plan, workers' compensation, coal workers' pneumoconiosis (CWP) and long-term disability. These liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. The average retirement and disability costs attributable to the low volatile metallurgical coal segment were $23 million for the nine months ended September 30, 2012 compared to $31 million for the nine months ended September 30, 2011. The decrease in the low volatile metallurgical coal retirement and disability costs was primarily attributable to a decrease in discount rates used to calculate the cost of the long-term liabilities and a modification of the salaried other post-retirement benefit plan. This improvement was offset, in part, by the reduction in production volumes which negatively impacted unit costs.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $30 million for the nine months ended September 30, 2012 compared to $27 million for the nine months ended September 30, 2011. Unit costs per low volatile metallurgical ton produced were higher in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 due to additional equipment and infrastructure placed into service after the 2011 period that is depreciated on a straight-line basis. These costs were offset by lower depletion charges related to lower volumes produced.

Changes in low volatile metallurgical coal inventory volumes and carrying value resulted in a decrease of $17 million to cost of goods sold in the nine months ended September 30, 2012 and an increase of $1 million to cost of goods sold in the nine months ended September 30, 2011. Produced low volatile metallurgical coal inventory was 0.4 million tons at September 30, 2012 compared to 0.2 million tons at September 30, 2011.

OTHER COAL SEGMENT

The other coal segment had a loss before income tax of $143 million for the nine months ended September 30, 2012 compared to a loss before income tax of $352 million for the nine months ended September 30, 2011. The other coal segment includes purchased coal activities, idle mine activities, as well as various activities assigned to the coal segment but not allocated to each individual mine.

Other coal segment produced coal sales includes revenue from the sale of 0.1 million tons of coal which was recovered during the reclamation process at idled facilities for the nine months ended September 30, 2012 and 0.3 million tons for the nine months ended September 30, 2011. The primary focus of the activity at these locations is reclaiming disturbed land in accordance with the mining permit requirements after final mining has occurred. The tons sold are incidental to total Company production or sales.

Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes to meet customer coal specifications and coal purchased from third parties and sold directly to our customers. The revenues were $13 million for the nine months ended September 30, 2012 compared to $37 million for the nine months ended September

30, 2011. The decrease was due to the purchase of additional tons of third party coal in the 2011 period due to a railroad bridge outage in order to meet contractual deliveries during the outage.

Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is offset by freight expense. Freight revenue was $126 million for the nine months ended September 30, 2011 compared to $156 million for the nine months ended September 30, 2011. The $30 million decrease in freight revenue was due to decreased shipments under contracts which CONSOL Energy contractually provides transportation services.

Miscellaneous other income was $225 million for the nine months ended September 30, 2012 compared to $53 million for the nine months ended September 30, 2011. The $172 million increase is due to the following items:

- Gain on sale of assets attributable to the Other Coal segment were $181 million in the nine months ended September 30, 2012 compared to $5 million in the nine months ended September 30, 2011. The change was primarily related to sales of non-producing assets in the Northern Powder River Basin that resulted in income of $151 million, as well as coal and surface lands in Illinois and West Virginia that resulted in income of $22 million. See Note 2—Acquisitions and Dispositions in the Notes to the Unaudited Consolidated Financial Statements for additional detail of these sales. The remaining change was related to various transactions that occurred throughout both periods, none of which were individually material.
- In the nine months ended September 30, 2012, $12 million of income was recognized related to contracts from certain thermal coal customers that were unable to take delivery of previously contracted coal tonnage. These customers agreed to buy out their contracts in order to be released from the requirements of taking delivery of previously committed tons. No such transactions were entered into in the year ended September 30, 2011.
- In the nine months ended September 30, 2011, a gain of $10 million was recognized for the issuance of a pipeline right-of-way to a third party. There were no such transactions in the nine months ended September 30, 2012.
- Equity in earnings of affiliates decreased $6 million due to lower earnings from our equity affiliates.

Other coal segment total costs were $513 million for the nine months ended September 30, 2012 compared to $620 million for the nine months ended September 30, 2011. The decrease of $107 million was due to the following items:

	For the nine months ended September 30,		
	2012	2011	Variance
Abandonment of long-lived assets	$—	$116	$(116)
Freight expense	126	156	(30)
Purchased Coal	32	57	(25)
PA Streams	—	5	(5)
Coal contract buyout	—	5	(5)
Closed and idle mines	112	80	32
Bailey Belt Incident	42	—	42
Other	201	201	—
Total Other Coal Segment Costs	$513	$620	$(107)

- Abandonment of long-lived assets were $116 million for the nine months ended September 30, 2011 as a result of the 2011 decision to permanently idle Mine 84.
- Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight expense is offset by freight revenue. The decrease in freight expense was due to decreased shipments under contracts which CONSOL Energy contractually provides transportation services.
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Purchased coal costs decreased approximately $25 million in the period-to-period comparison primarily due to coal purchases to fulfill various contracts during a railroad bridge outage that occurred in the 2011 period.

- PA Streams costs were $5 million for the nine months ended September 30, 2011 as a result of the recognition of an additional liability related to the environmental remediation of streams in Pennsylvania affected by our mines.
- Coal contract buyout costs decreased $5 million as a result of a lower priced coal sales contract being bought out in 2011 in order to sell the tons on a higher priced contract.

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- Closed and idle mine costs increased approximately $32 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. The increase was the result of $36 million additional costs related to reclamation liabilities and on-going idling costs incurred at the Fola Complex in the nine months ended September 30, 2012. Closed and idle mine costs increased $8 million as the result of a 2012 decision to temporarily idle Buchanan Mine in 2012. Closed and idle mine costs increased $4 million due to other changes in the operational status of various other mines, between idled and operating throughout both periods, none of which were individually material. Closed and idle mine costs decreased $16 million as the result of a 2011 decision to permanently abandon Mine 84 in 2011.
- Bailey Belt Incident costs represents expenses during the belt-reconstruction period related to continued advancement of the mines and on-going projects at the mines
- Other expenses related to the coal segment remained consistent for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011.

TOTAL GAS SEGMENT ANALYSIS for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011:
The gas segment contributed $25 million to earnings before income tax in the nine months ended September 30, 2012 compared to $53 million in the nine months ended September 30, 2011.

	For the Nine Months Ended September 30, 2012					Difference to Nine Months Ended September 30, 2011				
	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$281	$101	$84	$7	$473	$(64)	$(19)	$(4)	$(2)	$(89)
Related Party	2	—	—	—	2	(2)	—	—	—	(2)
Total Outside Sales	283	101	84	7	475	(66)	(19)	(4)	(2)	(91)
Gas Royalty Interest	—	—	—	35	35	—	—	—	(17)	(17)
Purchased Gas	—	—	—	2	2	—	—	—	(1)	(1)
Other Income	—	—	—	46	46	—	—	—	55	55
Total Revenue and Other Income	283	101	84	90	558	(66)	(19)	(4)	35	(54)
Lifting	28	31	9	1	69	(1)	(3)	(2)	—	(6)
Ad Valorem, Severance, and Other Taxes	7	7	3	2	19	(2)	(2)	2	1	(1)
Gathering	78	18	17	—	113	6	(2)	7	(1)	10
Gas Direct Administrative, Selling & Other	12	11	10	3	36	(12)	(6)	1	6	(11)
Depreciation, Depletion and Amortization	66	44	31	7	148	(9)	(4)	2	—	(11)
General & Administration	—	—	—	29	29	—	—	—	(6)	(6)
Gas Royalty Interest	—	—	—	28	28	—	—	—	(19)	(19)
Purchased Gas	—	—	—	2	2	—	—	—	(1)	(1)
Exploration and Other Costs	—	—	—	29	29	—	—	—	19	19
Other Corporate Expenses	—	—	—	56	56	—	—	—	7	7
Interest Expense	—	—	—	4	4	—	—	—	(3)	(3)
Total Cost	191	111	70	161	533	(18)	(17)	10	3	(22)
Earnings Before Noncontrolling Interest and Income Tax	92	(10)	14	(71)	25	(48)	(2)	(14)	32	(32)
Noncontrolling Interest	—	—	—	—	—	—	—	—	(4)	(4)
Earnings Before Income Tax	$92	$(10)	$14	$(71)	$25	$(48)	$(2)	$(14)	$36	$(28)

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COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $92 million to the total Company earnings before income tax for the nine months ended September 30, 2012 compared to $140 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas CBM sales volumes (in billion cubic feet)	66.8	68.6	(1.8)	(2.6)%
Average CBM sales price per thousand cubic feet sold	$4.24	$5.09	$(0.85)	(16.7)%
Average CBM lifting costs per thousand cubic feet sold	0.42	0.42	—	—%
Average CBM ad valorem, severance, and other taxes per thousand cubic feet sold	0.11	0.14	(0.03)	(21.4)%
Average CBM gathering costs per thousand cubic feet sold	1.17	1.04	0.13	12.5%
Average CBM direct administrative, selling & other costs per thousand cubic feet sold	0.18	0.34	(0.16)	(47.1)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	0.99	1.10	(0.11)	(10.0)%
Total Average CBM costs per thousand cubic feet sold	2.87	3.04	(0.17)	(5.6)%
Average Margin for CBM	$1.37	$2.05	$(0.68)	(33.2)%

CBM sales revenues were $283 million in the nine months ended September 30, 2012 compared to $349 million for the nine months ended September 30, 2011. The $66 million decrease was primarily due to a 16.7% decrease in average sales price per thousand cubic feet sold and a 2.6% decrease in average volumes sold. The decrease in CBM average sales price was the result of lower average market prices and various gas swap transactions that matured in each period. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 34.5 billion cubic feet of our produced CBM gas sales volumes for the nine months ended September 30, 2012 at an average price of $5.34 per thousand cubic feet. For the nine months ended September 30, 2011, these financial hedges represented 45.1 billion cubic feet at an average price of $5.37 per thousand cubic feet. CBM sales volumes decreased 1.8 billion cubic feet for the nine months ended September 30, 2012 compared to the 2011 year-to-date period primarily due to normal well declines without a corresponding increase in wells drilled and the Buchanan Mine idling, as previously discussed. Currently, the focus of the gas division is to develop its Marcellus and Utica acreage. At September 30, 2012, there were 4,493 gross CBM wells in production. At September 30, 2011, there were 4,397 gross CBM wells in production.

Total costs for the CBM segment were $191 million for the nine months ended September 30, 2012 compared to $209 million for the nine months ended September 30, 2011. Lower costs in the period-to-period comparison are primarily related to lower unit costs, coupled with decreased gas production as discussed above.

CBM lifting costs were $28 million for the nine months ended September 30, 2012 compared to $29 million for the nine months ended September 30, 2011. The $1 million decrease is primarily due to idle rig costs incurred during the 2011 period. The reduced costs were offset by lower sales volumes resulting in average unit costs of $0.42 in both periods.

CBM ad valorem, severance and other taxes were $7 million for the nine months ended September 30, 2012 compared to $9 million for the nine months ended September 30, 2011. Reduced severance tax expense was the result of lower average gas sales prices during 2012. Decreased costs, offset, in part, by lower sales volumes sold resulted in $0.03 decrease to average unit costs.

CBM gathering costs were $78 million for the nine months ended September 30, 2012 compared to $72 million for the nine months ended September 30, 2011. Higher average CBM gathering unit costs are related to increased power usage, higher compressor maintenance, higher equipment lease expenses and lower volumes sold in the period-to-period comparison.

CBM direct administrative, selling & other costs for the CBM segment were $12 million for the nine months ended September 30, 2012 compared to $24 million for the nine months ended September 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The decrease in direct administrative, selling & other costs was primarily due to reduced direct administrative labor and CBM volumes representing a smaller proportion of total natural gas volumes.

Depreciation, depletion and amortization attributable to the CBM segment was $66 million for the nine months ended September 30, 2012 compared to $75 million for the nine months ended September 30, 2011. There was approximately $45 million, or $0.68 per unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a units-of-production method of depreciation in the nine months ended September 30, 2012. The production portion of depreciation, depletion and amortization was $53 million, or $0.78 per unit-of-production in the nine months ended September 30, 2011. The CBM unit-of-production rate decreased due to revised rates which were generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. There was approximately $21 million, or $0.31 average per unit cost of depreciation, depletion and amortization relating to gathering and other equipment reflected on a straight line basis for the nine months ended September 30, 2012. The non-production related depreciation, depletion and amortization was $22 million, or $0.32 per thousand cubic feet for the nine months ended September 30, 2011.

SHALLOW OIL AND GAS SEGMENT

The Shallow Oil and Gas segment had a loss before income tax of $10 million for the nine months ended September 30, 2012 compared to a loss before income tax of $8 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas Shallow Oil and Gas sales volumes (in billion cubic feet)	21.8	24.0	(2.2)	(9.2)%
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.62	$5.00	$(0.38)	(7.6)%
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	1.40	1.44	(0.04)	(2.8)%
Average Shallow Oil and Gas ad valorem, severance, and other taxes per thousand cubic feet sold	0.34	0.38	(0.04)	(10.5)%
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	0.81	0.84	(0.03)	(3.6)%
Average Shallow Oil and Gas direct administrative, selling & other costs per thousand cubic feet sold	0.49	0.71	(0.22)	(31.0)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	2.01	1.98	0.03	1.5%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	5.05	5.35	(0.30)	(5.6)%
Average Margin for Shallow Oil and Gas	$(0.43)	$(0.35)	$(0.08)	22.9%

Shallow Oil and Gas sales revenues were $101 million for the nine months ended September 30, 2012 compared to $120 million for the nine months ended September 30, 2011. The $19 million decrease was primarily due to the 9.2% decrease in volumes sold as well as the 7.6% decrease in average sales price. The decrease in shallow oil and gas average sales price is the result of lower average market prices and various gas swap transactions that matured in each period. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 14.3 billion cubic feet of our produced shallow oil and gas sales volumes for the nine months ended September 30, 2012 at an average price of $5.23 per thousand cubic feet. For the nine months ended September 30, 2011, these financial hedges represented 8.0 billion cubic feet at an average price of $4.97 per thousand cubic feet. At September 30, 2012, there were 9,936 gross Shallow Oil and Gas wells in production. At September 30, 2011, there were 10,015 gross Shallow Oil and Gas wells in production.

Total costs for the shallow oil and gas segment were $111 million for the nine months ended September 30, 2012 compared to $128 million for the nine months ended September 30, 2011. The decrease is attributable to decreased variable costs associated with the lower sales volumes and lower average unit costs.
Shallow Oil and Gas lifting costs were $31 million for the nine months ended September 30, 2012 compared to $34 million for the nine months ended September 30, 2011. The $3 million decrease to total costs and $0.04 decrease to average unit costs is due to lower road maintenance and lower contract services in the current period, offset, in part by lower volumes sold.

Shallow Oil and Gas ad valorem, severance and other taxes were $7 million for the nine months ended September 30, 2012 compared to $9 million for the nine months ended September 30, 2011. The decrease to total costs and average unit costs was primarily due to reduced severance tax expense caused by lower average gas sales prices during the current year-to-date period.

Shallow Oil and Gas gathering costs were $18 million for the nine months ended September 30, 2012 compared to $20 million for the nine months ended September 30, 2011. Gathering costs decreased primarily due to lower compressor maintenance and lower equipment lease expenses in the period-to-period comparison The impact of these reductions on unit costs were offset, in part, by lower sales volumes.

Shallow Oil and Gas direct administrative, selling & other costs were $11 million for the nine months ended September 30, 2012 compared to $17 million for the nine months ended September 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The $6 million decrease in the period-to-period comparison is due to reduced direct administrative labor and Shallow Oil and Gas volumes representing a smaller proportion of total natural gas volumes.

Depreciation, depletion and amortization costs were $44 million for the nine months ended September 30, 2012 compared to $48 million for the nine months ended September 30, 2011. There was approximately $38 million, or $1.75 per unit-of production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the nine months ended September 30, 2012. There was approximately $43 million, or $1.74 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the nine months ended September 30, 2011. The rate is calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $6 million, or $0.26 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the nine months ended September 30, 2012. There was $5 million, or $0.24 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the nine months ended September 30, 2011.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $14 million to the total Company earnings before income tax for the nine months ended September 30, 2012 compared to $28 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Produced Gas Marcellus sales volumes (in billion cubic feet)	24.0	19.7	4.3	21.8 %
Average Marcellus sales price per thousand cubic feet sold	$3.48	$4.48	$(1.00)	(22.3)%
Average Marcellus lifting costs per thousand cubic feet sold	0.39	0.57	(0.18)	(31.6)%
Average Marcellus ad valorem, severance, and other taxes per thousand cubic feet sold	0.13	0.05	0.08	160.0 %
Average Marcellus gathering costs per thousand cubic feet sold	0.64	0.49	0.15	30.6 %
Average Marcellus direct administrative, selling & other costs per thousand cubic feet sold	0.43	0.43	—	— %

Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	1.30	1.50	(0.20)	(13.3)%
Total Average Marcellus costs per thousand cubic feet sold	2.89	3.04	(0.15)	(4.9)%
Average Margin for Marcellus	$0.59	$1.44	$(0.85)	(59.0)%

The Marcellus segment sales revenues were $84 million for the nine months ended September 30, 2012 compared to $88 million for the nine months ended September 30, 2011. The $4 million decrease is primarily due to a 22.3% decrease to average sales prices, partially offset by a 21.8% increase in volumes sold in the period-to-period comparison. The decrease in Marcellus average sales price was the result of the decline in general market prices and by various gas swap transactions that matured in the nine months ended September 30, 2012. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 8.5 billion cubic feet of our produced Marcellus gas sales volumes for the nine months ended September 30, 2012 at an average price of $4.97 per thousand cubic feet. For the nine months ended September 30, 2011, these financial hedges represented 6.8 billion cubic feet at an average price of $4.60 per thousand cubic feet. The increase in sales volumes is primarily due to additional wells coming on-line from our on-going drilling program, offset, in part, by a 10.7 billion cubic feet decrease in sales volumes related to the 2011 Antero divestiture and 2011 Noble joint venture. At September 30, 2012, there were 194 gross Marcellus Shale wells in production. At September 30, 2011, there were 122 gross Marcellus Shale wells in production

Marcellus lifting costs were $9 million for the nine months ended September 30, 2012 compared to $11 million for the nine months ended September 30, 2011. The decrease to average unit costs is due to lower well servicing costs, well tending costs and additional sales volumes during the 2012 year-to-date period.

Marcellus ad valorem, severance and other taxes were $3 million for the nine months ended September 30, 2012 compared to $1 million for the nine months ended September 30, 2011. The increase in the current period per unit cost is primarily due to new legislation passed in the state of Pennsylvania (Act 13 of 2012, House Bill 1950). This legislation permits Pennsylvania counties to impose annual fees on unconventional gas wells located within Pennsylvania.

Marcellus gathering costs were $17 million for the nine months ended September 30, 2012 compared to $10 million for the nine months ended September 30, 2011. The increase to average unit costs is due to higher firm transportation costs and the 4.3 billion cubic feet of additional volumes sold.

Marcellus direct administrative, selling & other costs were $10 million for the nine months ended September 30, 2012 compared to $9 million for the nine months ended September 30, 2011. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The increase in direct administrative, selling & other costs was primarily due to an increase in direct administrative labor. The impact on average unit costs from the increase in direct administrative labor was offset by higher volumes sold.

Depreciation, depletion and amortization costs were $31 million for the nine months ended September 30, 2012 compared to $29 million for the nine months ended September 30, 2011. There was approximately $28 million, or $1.20 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation in the nine months ended September 30, 2012. There was approximately $22 million, or $1.10 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the nine months ended September 30, 2011. The rate was calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $3 million, or $0.10 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis for the nine months ended September 30, 2012. There was $7 million, or $0.40 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the nine months ended September 30, 2011. The decrease in Marcellus gathering and other equipment depreciation, depletion and amortization relates to the sale of assets to CONE Gathering LLC (CONE), a 50% owned affiliate. CONE was created as part of the Noble transaction during 2011. See Note 2 - Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional information.

OTHER GAS SEGMENT

The other gas segment includes activity not assigned to the CBM, Shallow Oil and Gas or Marcellus gas segments. This segment includes purchased gas activity, gas royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific gas segment.

Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee and the Utica Shale in Ohio. Revenue from these operations were approximately $7 million for the nine months ended September 30, 2012 and $9 million for the nine months ended September 30, 2011. Total costs related to these other sales were $13 million for the 2012 period and were $7 million for the 2011 period. The increase in costs in the period-to-period comparison were primarily attributable to increased direct administrative, selling & other costs. Increased direct administrative, selling and other costs is primarily related to higher proportional allocation relating to the Utica operating area during 2012. A per unit analysis of the other operating costs in Chattanooga Shale and Utica Shale is not meaningful due to the low volumes produced in the period-to-period analysis.

Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas sales revenue was $35 million for the nine months ended September 30, 2012 compared to $52 million for the nine months ended September 30, 2011. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	13.2	12.2	1.0	8.2 %
Average Sales Price Per thousand cubic feet	$ 2.63	$ 4.27	$ (1.64)	(38.4)%

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $2 million for the nine months ended September 30, 2012 and $3 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	0.8	0.7	0.1	14.3 %
Average Sales Price Per thousand cubic feet	$ 2.90	$ 4.50	$ (1.60)	(35.6)%

Other income was $46 million for the nine months ended September 30, 2012 compared to a loss of $9 million for the nine months ended September 30, 2011. The $55 million increase was primarily due to $24 million of additional interest income relating to the notes receivable from the Noble joint venture transaction, $10 million of additional gains on dispositions of non-core acreage and equipment, and a $4 million increase relating to earnings from equity affiliates. Additionally, CONSOL incurred a $58 million loss on the Noble transaction during 2011, partially offset by a gain on the sale to Antero of an overriding royalty interest of $41 million during 2011.

General and administrative costs are allocated to the total gas segment based on percentage of total revenue and percentage of total projected capital expenditures. Costs were $29 million for the nine months ended September 30, 2012 compared to $35 million for the nine months ended September 30, 2011. Refer to the discussion of total company general and administrative costs contained in the section "Net Income Attributable to CONSOL Energy Shareholders" of this quarterly report for a detail cost explanation.

Royalty interest gas costs represent the costs related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas costs were $28 million for the nine months ended September 30, 2012 compared to $47 million for the nine months ended September 30, 2011. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	13.2	12.2	1.0	8.2 %
Average Cost Per thousand cubic feet sold	$ 2.12	$ 3.81	$ (1.69)	(44.4)%

Purchased gas volumes represent volumes of gas purchased from third-party producers that we sell. Purchased gas volumes also reflect the impact of pipeline imbalances. The lower average cost per thousand cubic feet is due to overall price changes and contractual differences among customers in the period-to-period comparison. Purchased gas costs were $2 million for the nine months ended September 30, 2012 compared to $3 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	1.0	0.9	0.1	11.1 %
Average Cost Per thousand cubic feet sold	$ 2.22	$ 3.11	$ (0.89)	(28.6)%

Exploration and other costs were $29 million for the nine months ended September 30, 2012 compared to $10 million for the nine months ended September 30, 2011. The $19 million decrease is due to the following items:

	For the Nine Months Ended September 30,				
	2012	2011	Variance	Percent Change	
Lease Expiration Costs	$19	$7	$12	171.4	%
Dry Hole Costs	7	2	5	250.0	%
Exploration	3	1	2	200.0	%
Total Exploration and Other Costs	$29	$10	$19	190.0	%

- Lease Expiration costs increased $12 million due to various lease expirations relating to locations where CONSOL Energy allowed primary lease terms to expire.
- Dry Hole Costs increased $5 million primarily due to a favorable settlement involving defective pipe in 2011 which reduced expenses in the nine months ended September 30, 2011.
- Exploration expenses increased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses were $56 million for the nine months ended September 30, 2012 compared to $49 million for the nine months ended September 30, 2011. The $7 million increase in the period-to-period comparison was made up of the following items:

	For the Nine Months Ended September 30,				
	2012	2011	Variance	Percent Change	
PA Impact Fee	$4	$—	$4	100.0	%
Stock - based compensation	15	13	2	15.4	%
Short Term Incentive Compensation	20	19	1	5.3	%
Bank Fee	5	5	—	—	%
Unutilized Firm Transportation	9	11	(2)	(18.2	)%
Other	3	1	2	200.0	%
Total Other Corporate Expenses	$56	$49	$7	14.3	%

- PA impact fees are related to legislation in the state of Pennsylvania (Act 13 of 2012, House Bill 1950) which was signed into law during the first quarter of 2012. This legislation permits Pennsylvania counties to impose annual fees on unconventional gas wells located within their borders. As part of the legislation, all unconventional wells which were drilled prior to January 1, 2012 were assessed an initial fee related to periods prior to 2012. The $4 million represents this one-time initial assessment on wells drilled prior to January 1, 2012. On-going PA impact fees which relate to current year wells drilled are included as part of ad valorem, severance and other taxes in the Marcellus gas segment.
- Stock-based compensation was higher in the period-to-period comparison primarily due to the increased allocation from CONSOL Energy as a result of an increase in total CONSOL Energy stock-based compensation expense. Stock-based compensation costs are allocated to the gas segment based on revenue and capital expenditure projections between coal and gas.
- The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for safety, production and unit costs. Short-term incentive compensation expense was higher for the 2012 year-to-date period compared to the 2011 year-to-date period due to the projected higher payouts.
- Bank Fees remained consistent in the period-to-period comparison.
- Unutilized firm transportation costs represent pipeline transportation capacity the gas segment has obtained to enable gas production to flow uninterrupted as sales volumes increase. The $2 million decrease is due to increased utilization of pipeline capacity in the 2012 period.
- Other corporate related expense increased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense related to the gas segment was $4 million for the nine months ended September 30, 2012 compared to $7 million for the nine months ended September 30, 2011. Interest was incurred by the gas segment on the CNX Gas revolving credit facility, a capital lease and debt that was held by a variable interest entity. The $3 million decrease was primarily due to lower levels of borrowings on the revolving credit facility in the period-to-period comparison.

Noncontrolling interest represents 100% of the earnings impact of a third party in which CONSOL Energy held no ownership interest. The variance in the noncontrolling amounts reflects the third parties variance in earnings in the period-to-period comparison. In the nine month's ended September 30, 2011, the drilling services contract was bought out. Subsequent to this transaction, the noncontrolling interest was de-consolidated.

OTHER SEGMENT ANALYSIS for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011:

The other segment includes activity from the sales of industrial supplies, the transportation operations and various other corporate activities that are not allocated to the coal or gas segment. The other segment had a loss before income tax of $145 million for the nine months ended September 30, 2012 compared to a loss before income tax of $222 million for the nine months ended September 30, 2011. The other segment also includes total Company income tax expense of $60 million for the nine months ended September 30, 2012 compared to $113 million for the nine months ended September 30, 2011.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Sales—Outside	$281	$252	$29	11.5 %
Other Income	17	14	3	21.4 %
Total Revenue	298	266	32	12.0 %
Cost of Goods Sold and Other Charges	250	282	(32)	(11.3)%
Depreciation, Depletion & Amortization	18	14	4	28.6 %
Taxes Other Than Income Tax	9	9	—	— %
Interest Expense	166	183	(17)	(9.3)%
Total Costs	443	488	(45)	(9.2)%
Loss Before Income Tax	(145)	(222)	77	34.7 %
Income Tax	60	113	(53)	(46.9)%
Net Loss	$(205)	$(335)	$130	(38.8)%

Industrial supplies:

Total revenue from industrial supplies was $193 million for the nine months ended September 30, 2012 compared to $172 million for the nine months ended September 30, 2011. The increase was related to higher sales volumes.

Total costs related to industrial supply sales were $186 million for the nine months ended September 30, 2012 compared to $173 million for the nine months ended September 30, 2011. The increase of $13 million was primarily related to higher sales volumes and various changes in inventory costs, none of which were individually material.

Transportation operations:

Total revenue from transportation operations was $95 million for the nine months ended September 30, 2012 compared to $88 million for the nine months ended September 30, 2011. The increase of $7 million was primarily attributable to higher per ton thru-put rates and increased tonnage thru-put at the CNX Marine Terminal.

Total costs related to the transportation operations were $65 million for the nine months ended September 30, 2012 compared to $66 million for the nine months ended September 30, 2011. The decrease was due to various items in both periods, none of which were individually material.

Miscellaneous other:

Additional other income of $10 million was recognized for the nine months ended September 30, 2012 compared to $6 million for the nine months ended September 30, 2011. The $4 million increase was primarily due to the earnings from our equity affiliates that are included in the other segment.

Other corporate costs in the other segment include interest expense, acquisition and financing costs and various other miscellaneous corporate charges. Total other costs were $192 million for the nine months ended September 30, 2012 compared to $249 million for the nine months ended September 30, 2011. Other corporate costs decreased due to the following items:

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	For the Nine Months Ended September 30,		
	2012	2011	Variance
Interest Expense	$166	$183	$(17)
Loss on extinguishment of debt	—	16	(16)
Transaction and financing fees	—	15	(15)
Bank fees	10	16	(6)
Evaluation fees for non-core asset dispositions and other legal charges	4	5	(1)
Other	12	14	(2)
	$192	$249	$(57)

- Interest Expense decreased $17 million in the period-to-period comparison. Interest expense decreased due to an increase in capitalized interest due to higher capital expenditures for major construction projects in the current period. Capital expenditures for coal activities increased $283 million in the period-to-period comparison.
- On April 11, 2011, CONSOL Energy redeemed all of its outstanding $250 million, 7.875% senior secured notes due March 1, 2012 in accordance with the terms of the indenture governing these notes. The loss on extinguishment of debt was $16 million, which primarily represented the interest that would have been paid on these notes if held to maturity.
- Transaction and financing fees of $15 million incurred in the nine months ended September 30, 2011 related to the solicitation of consents of the long-term bonds needed in order to clarify the indentures that relate to joint arrangements with respect to its oil and gas properties.
- Bank fees decreased $6 million due to lower borrowings on the revolving credit facilities in the period-to-period comparison.
- Evaluation fees for non-core asset dispositions and other legal charges decreased $1 million in the period-to-period comparison due to various corporate initiatives that began after 2010.
- Other corporate items decreased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 20.2% for the nine months ended September 30, 2012 compared to 20.6% for the nine months ended September 30, 2011. The slight decrease in the effective tax rate for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011 was attributable to the relationship between pre-tax earnings and percentage depletion. Also effecting the rate was the gain on sale of CONSOL Energy's non-producing Northern Powder River Basin (PRB) assets on June 29, 2012 of $151 million and various adjustments to the accrued income taxes versus the actual income taxes filed. See Note 5—Income Taxes of the Notes to the Condensed Consolidated Financial Statements of this Form 10-Q for additional information.

	For the Nine Months Ended September 30,			
	2012	2011	Variance	Percent Change
Total Company Earnings Before Income Tax	$299	$550	$(251)	(45.6)%
Income Tax Expense	$60	$113	$(53)	(46.9)%
Effective Income Tax Rate	20.2%	20.6%	(0.4)%	

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Liquidity and Capital Resources

CONSOL Energy generally has satisfied its working capital requirements and funded its capital expenditures and debt service obligations with cash generated from operations and proceeds from borrowings. CONSOL Energy's $1.5 billion Senior Secured Credit Agreement expires April 12, 2016. CONSOL Energy's credit facility allows for up to $1.5 billion of borrowings and letters of credit. CONSOL Energy can request an additional $250 million increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on a ratio of financial covenant debt to twelve-month trailing earnings before interest, taxes, depreciation, depletion and amortization (EBITDA), measured quarterly. The facility includes a minimum interest coverage ratio covenant of no less than 2.50 to 1.00, measured quarterly. The interest coverage ratio is calculated as the ratio of EBITDA to cash interest expense of CONSOL Energy and certain of its subsidiaries. The interest coverage ratio was 5.20 to 1.00 at September 30, 2012. The facility includes a maximum leverage ratio covenant of no more than 4.75 to 1.00 through March 2013, and no more than 4.50 to 1.00 thereafter, measured quarterly. The leverage ratio is calculated as the ratio of financial covenant debt to twelve-month trailing EBITDA for CONSOL Energy and certain subsidiaries. Financial covenant debt is comprised of the outstanding indebtedness and specific letters of credit, less cash on hand, for CONSOL Energy and certain of its subsidiaries. EBITDA, as used in the covenant calculation, excludes non-cash compensation expenses, non-recurring transaction expenses, uncommon gains and losses, gains and losses on discontinued operations and includes cash distributions received from affiliates plus pro-rata earnings from material acquisitions. The leverage ratio was 2.43 to 1.00 at September 30, 2012. The facility also includes a senior secured leverage ratio covenant of no more than 2.00 to 1.00, measured quarterly. The senior secured leverage ratio is calculated as the ratio of secured debt to EBITDA. Secured debt is defined as the outstanding borrowings and letters of credit on the revolving credit facility. The senior secured leverage ratio was 0.08 to 1.00 at September 30, 2012. Covenants in the facility limit our ability to dispose of assets, make investments, purchase or redeem CONSOL Energy common stock, pay dividends, merge with another company and amend, modify or restate, in any material way, the senior unsecured notes. At September 30, 2012, the facility had no outstanding borrowings and $100 million of letters of credit outstanding, leaving $1.4 billion of unused capacity. From time to time, CONSOL Energy is required to post financial assurances to satisfy contractual and other requirements generated in the normal course of business. Some of these assurances are posted to comply with federal, state or other government agencies statutes and regulations. We sometimes use letters of credit to satisfy these requirements and these letters of credit reduce our borrowing facility capacity.

CONSOL Energy also has an accounts receivable securitization facility. This facility allows the Company to receive, on a revolving basis, up to $200 million of short-term funding and letters of credit. The accounts receivable facility supports sales, on a continuous basis to financial institutions, of eligible trade accounts receivable. CONSOL Energy has agreed to continue servicing the sold receivables for the financial institutions for a fee based upon market rates for similar services. The cost of funds is based on commercial paper rates plus a charge for administrative services paid to financial institutions. At September 30, 2012, eligible accounts receivable totaled approximately $200 million. At September 30, 2012, the facility had no outstanding borrowings and $161 million of letters of credit outstanding, leaving $39 million of unused capacity.

CNX Gas' $1.0 billion Senior Secured Credit Agreement expires April 12, 2016. The facility is secured by substantially all of the assets of CNX Gas and its subsidiaries. CNX Gas' credit facility allows for up to $1.0 billion for borrowings and letters of credit. CNX Gas can request an additional $250 million increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. The facility includes a minimum interest coverage ratio covenant of no less than 3.00 to 1.00, measured quarterly. The interest coverage ratio is calculated as the ratio of EBITDA to cash interest expense for CNX Gas and its subsidiaries. The interest coverage ratio was 42.40 to 1.00 at September 30, 2012. The facility also includes a maximum leverage ratio covenant of no more than 3.50 to 1.00, measured quarterly. The leverage ratio is calculated as the ratio of financial covenant debt to twelve-month trailing EBITDA for CNX Gas and its subsidiaries. Financial covenant debt is comprised of the outstanding indebtedness and letters of credit, less cash on hand, for CNX Gas and its subsidiaries. EBITDA, as used in the covenant calculation, excludes non-cash compensation expenses, non-recurring transaction expenses, gains and losses on the sale of assets, uncommon gains and losses, gains and losses on discontinued operations and includes cash distributions received from affiliates plus pro-rata earnings from material acquisitions. The leverage ratio was 0.00 to 1.00 at September 30, 2012. Covenants in the facility limit CNX Gas' ability to dispose of assets, make investments, pay dividends and merge with another company. The credit facility allows unlimited investments in joint ventures for the development and operation of gas gathering systems and provides for $600,000 of loans, advances and dividends from CNX Gas to CONSOL Energy. Investments in the CONE are unrestricted. At September 30, 2012, the facility had no amounts drawn and $70 million of letters of credit outstanding, leaving $930 million of unused capacity.

Uncertainty in the financial markets brings additional potential risks to CONSOL Energy. The risks include declines in our stock price, less availability and higher costs of additional credit, potential counterparty defaults, and commercial bank failures. Financial market disruptions may impact our collection of trade receivables. As a result, CONSOL Energy regularly

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monitors the creditworthiness of our customers. We believe that our current group of customers are financially sound and represent no abnormal business risk.

CONSOL Energy believes that cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major acquisitions), scheduled debt payments, anticipated dividend payments and to provide required letters of credit. Nevertheless, the ability of CONSOL Energy to satisfy its working capital requirements, to service its debt obligations, to fund planned capital expenditures or to pay dividends will depend upon future operating performance, which will be affected by prevailing economic conditions in the coal and gas industries and other financial and business factors, some of which are beyond CONSOL Energy's control.
In order to manage the market risk exposure of volatile natural gas prices in the future, CONSOL Energy enters into various physical gas supply transactions with both gas marketers and end users for terms varying in length. CONSOL Energy has also entered into various gas swap transactions that qualify as financial cash flow hedges, which exist parallel to the underlying physical transactions. The fair value of these contracts was a net asset of $134 million at September 30, 2012. The ineffective portion of these contracts was insignificant to earnings in the three months and nine months ended September 30, 2012. No issues related to our hedge agreements have been encountered to date.
CONSOL Energy frequently evaluates potential acquisitions. CONSOL Energy has funded acquisitions with cash generated from operations and a variety of other sources, depending on the size of the transaction, including debt and equity financing. There can be no assurance that additional capital resources, including debt and equity financing, will be available to CONSOL Energy on terms which CONSOL Energy finds acceptable, or at all.

Cash Flows (in millions)

	For the Nine Months Ended September 30,		
	2012	2011	Change
Cash flows from operating activities	$530	$1,252	$(722)
Cash used in investing activities	$(587)	$(231)	$(356)
Cash used in financing activities	$(88)	$(581)	$493

Cash flows provided by operating activities changed in the period-to-period comparison primarily due to the following items:

- Operating cash flow decreased $722 million in 2012 due to lower net income in the period-to-period comparison.
- Operating cash flows decreased due to various other changes in operating assets, operating liabilities, other assets and other liabilities which occurred throughout both years, none of which were individually material.

Net cash used in investing activities changed in the period-to-period comparison primarily due to the following items:

- Total capital expenditures increased $155 million to $1,152 million in the nine months ended September 30, 2012 compared to $997 million in the nine months ended September 30, 2011. Capital expenditures for coal and other activities increased $283 million in the period-to-period comparison. The ongoing development and expenditures of the BMX mine, which is scheduled to go on-line in 2014, increased $51 million in the period-to-period comparison. Capital expenditures for the Northern West Virginia RO system increased $71 million in the period-to-period comparison. In the nine months ended September 30, 2012 capital expenditures related to long wall roof shields increased $70 million in the period-to-period comparison. The remaining $91 million increase was due to various projects throughout both periods, none of which were individually material. Capital expenditures for the gas segment decreased $128 million primarily due to a decrease in CBM drilling and gathering system expenditures in the period-to-period comparison.
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Proceeds from the sale of assets decreased $111 million in the period-to-period comparison. The decrease was due to $344 million received on September 30, 2012 related to the Noble Transaction compared to $489 million in net proceeds related to the Noble Transaction received on September 30, 2011. On September 21, 2011, CONSOL Energy sold an overriding royalty to Antero Resources Appalachian Corp. for $190 million of net proceeds. These decreases were offset, in part, by the sale of non-producing Northern Powder River Basin (PRB) assets on June 29, 2012, which resulted in proceeds of $170 million. Also, the sale of various other properties in 2012 which resulted in proceeds of $39 million. The remaining $15 million period-to-period increase was from various other transactions that occurred throughout both periods, none of which were individually material. See Note 2 -

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Acquisitions and Dispositions, in the Consolidated Financial Statements included in this Form 10-Q for more information.

- Distributions From, net of (Investments In), Equity Affiliates decreased $90 million in the period-to-period comparison. During the 2012 period, $35 million was contributed to CONE in order to meet the operating and capital expenditure needs of the joint venture. The joint venture, of which CONSOL Energy owns 50%, was established on September 30, 2011 to develop and operate the gas gathering system in the Marcellus Shale play. On September 30, 2011, CONSOL Energy received a $68 million cash distribution from CONE Gathering LLC. See Note 2-Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional details. The remaining $13 million increase was primarily due to additional cash distributions received from various Equity Affiliates in the period-to-period comparison.

Net cash used in financing activities changed in the period-to-period comparison primarily due to the following items:

- In 2011, proceeds of $250 million were received in connection with the issuance of $250 million of 6.375% senior unsecured notes due in March 2021.
- In 2011, CONSOL Energy repaid $200 million of borrowings under the accounts receivable securitization facility.
- In 2011, CONSOL Energy paid outstanding borrowings of $284 million under the revolving credit facilities.
- In April 2011, CONSOL Energy paid $266 million, including a make-whole provision, to redeem the 7.875% notes that were due in March 2012.
- Dividends of $85 million were paid in 2012 compared to $68 million in 2011. This is due to the increase of the quarterly dividend by 25%, or $0.025 per share, to $0.125 per share in the 2012 period.

The following is a summary of our significant contractual obligations at September 30, 2012 (in thousands):

	Payments due by Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Purchase Order Firm Commitments	$354,358	$13,688	$—	$—	$368,046
Gas Firm Transportation	79,338	152,381	133,978	453,358	819,055
CONE Gathering Commitments	47,250	227,775	385,700	1,040,800	1,701,525
Long-Term Debt	12,968	8,263	1,507,665	1,611,334	3,140,230
Interest on Long-Term Debt	244,977	490,592	491,303	420,741	1,647,613
Capital (Finance) Lease Obligations	9,097	14,782	10,902	26,063	60,844
Interest on Capital (Finance) Lease Obligations	4,005	6,335	4,655	4,161	19,156
Operating Lease Obligations	98,609	168,017	105,010	155,431	527,067
Long-Term Liabilities—Employee Related (a)	227,653	468,513	482,271	2,367,736	3,546,173
Other Long-Term Liabilities (b)	359,314	134,767	88,856	480,304	1,063,241
Total Contractual Obligations (c)	$1,437,569	$1,685,113	$3,210,340	$6,559,928	$12,892,950

(a) Long-Term Liabilities—Employee Related include other post-employment benefits, work-related injuries and illnesses. Estimated salaried retirement contributions required to meet minimum funding standards under ERISA are excluded from the pay-out table due to the uncertainty regarding amounts to be contributed. Estimated 2012 contributions are expected to approximate $110 million.

(b) Other long-term liabilities include mine reclamation and closure and other long-term liability costs.

(c)

The significant obligation table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

Debt

At September 30, 2012, CONSOL Energy had total long-term debt of $3.201 billion outstanding, including the current portion of long-term debt of $22 million. This long-term debt consisted of:

- An aggregate principal amount of $1.5 billion of 8.00% senior unsecured notes due in April 2017. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy's subsidiaries.

- An aggregate principal amount of $1.25 billion of 8.25% senior unsecured notes due in April 2020. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy's subsidiaries.
- An aggregate principal amount of $250 million of 6.375% senior unsecured notes due in March 2021. Interest on the notes is payable March 1 and September 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy's subsidiaries.
- An aggregate principal amount of $103 million of industrial revenue bonds which were issued to finance the Baltimore port facility and bear interest at 5.75% per annum and mature in September 2025. Interest on the industrial revenue bonds is payable March 1 and September 1 of each year.
- An aggregate principal amount of $6 million on other various rate notes maturing through June 2031.
- $31 million in advance royalty commitments with an average interest rate of 6.73% per annum.
- An aggregate principal amount of $61 million of capital leases with a weighted average interest rate of 6.36% per annum.

At September 30, 2012, CONSOL Energy also had no outstanding borrowings and had approximately $100 million of letters of credit outstanding under the $1.5 billion senior secured revolving credit facility.
At September 30, 2012, CONSOL Energy had no outstanding borrowings and had $161 million of letters of credit outstanding under the accounts receivable securitization facility.
At September 30, 2012, CNX Gas, a wholly owned subsidiary of CONSOL Energy, had no outstanding borrowings and approximately $70 million of letters of credit outstanding under its $1.0 billion secured revolving credit facility.

Total Equity and Dividends

CONSOL Energy had total equity of $3.8 billion at September 30, 2012 and $3.6 billion at December 31, 2011. Total equity increased primarily due to net income, adjustments to actuarial liabilities, and the amortization of stock-based compensation awards. These increases were offset, in part, by the declaration of dividends, changes in the fair value of cash flow hedges and the issuance of treasury stock. See the Consolidated Statements of Stockholders' Equity in Item 1 of this Form 10-Q for additional details.
Dividend information for the current year to date were as follows:

Declaration Date	Amount Per Share	Record Date	Payment Date
October 26, 2012	$0.125	November 9, 2012	November 23, 2012
July 27, 2012	$0.125	August 10, 2012	August 24, 2012
April 27, 2012	$0.125	May 11, 2012	May 25, 2012
January 27, 2012	$0.125	February 7, 2012	February 21, 2012

The declaration and payment of dividends by CONSOL Energy is subject to the discretion of CONSOL Energy's Board of Directors, and no assurance can be given that CONSOL Energy will pay dividends in the future. CONSOL Energy's Board of Directors determines whether dividends will be paid quarterly. The determination to pay dividends will depend upon, among other things, general business conditions, CONSOL Energy's financial results, contractual and legal restrictions regarding the payment of dividends by CONSOL Energy, planned investments by CONSOL Energy and such other factors as the Board of Directors deems relevant. Our credit facility limits our ability to pay dividends in excess of an annual rate of $0.50 per share when our leverage ratio exceeds 4.50 to 1.00 or our availability is less than or equal to $100 million. The leverage ratio was 2.43 to 1.00 and our availability was approximately $1.4 billion at September 30, 2012. The credit facility does not permit dividend payments in the event of default. The indentures to the 2017, 2020 and 2021 notes limit dividends to $0.50 per share annually unless several conditions are met. Conditions include no defaults, ability to incur additional debt and other payment limitations under the indentures. There were no defaults in the nine months ended September 30, 2012.

Off-Balance Sheet Transactions

CONSOL Energy does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on CONSOL Energy's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the Notes to the Unaudited Consolidated Financial Statements. CONSOL Energy participates in various multi-employer benefit plans such as the UMWA 1974 Pension Plan, the UMWA Combined Benefit Fund and the UMWA 1993 Benefit Plan which generally accepted accounting principles recognize on a pay as you go basis. These benefit arrangements may result in additional liabilities that are not recognized on the balance sheet at September 30,

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2012. The various multi-employer benefit plans are discussed in Note 17—Other Employee Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of the December 31, 2011 Form 10-K. CONSOL Energy also uses a combination of surety bonds, corporate guarantees and letters of credit to secure our financial obligations for employee-related, environmental, performance and various other items which are not reflected on the balance sheet at September 30, 2012. Management believes these items will expire without being funded. See Note 11—Commitments and Contingencies in the Notes to the Unaudited Consolidated Financial Statements included in Item 1 of this Form 10-Q for additional details of the various financial guarantees that have been issued by CONSOL Energy.

Recent Accounting Pronouncements

In July 2012, the Financial Accounting Standards Board issued update 2012- 2 - Intangibles - Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment. The update is intended to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by simplifying how an entity tests those assets for impairment. The update is also intended to improve the consistency in impairment testing guidance among long-lived asset categories. Previous guidance required an entity to test indefinite-lived intangible assets for impairment by comparing the fair value of the asset with its carrying amount at least on an annual basis. If the carrying amount exceeded its fair value, an entity needed to recognize an impairment loss in the amount of the excess. The amendment to this update allows an entity to first assess the qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. This assessment will determine whether it is necessary to perform quantitative impairment tests. This type of testing results in guidance that is similar to the goodwill impairment testing in Update 2011-08. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012 with early adoption permitted for impairment tests performed as of July 27, 2012. We believe adoption of this new guidance will not have a material impact on CONSOL Energy's financial statements.

Forward-Looking Statements

We are including the following cautionary statement in this Quarterly Report on Form 10-Q to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf, of us. With the exception of historical matters, the matters discussed in this Quarterly Report on Form 10-Q are forward-looking statements (as defined in Section 21E of the Exchange Act) that involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words “believe,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “estimate,” “plan,” “predict,” “project,” or their negatives, or other expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this Quarterly Report on Form 10-Q speak only as of the date of this Quarterly Report on Form 10-Q; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- deterioration in global economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets cause conditions we cannot predict;
- a significant or extended decline in prices we receive for our coal and natural gas affecting our operating results and cash flows;

- our customers extending existing contracts or entering into new long-term contracts for coal;
- our reliance on major customers;
- our inability to collect payments from customers if their creditworthiness declines;
- the disruption of rail, barge, gathering, processing and transportation facilities and other systems that deliver our coal and natural gas to market;
- a loss of our competitive position because of the competitive nature of the coal and natural gas industries, or a loss of our competitive position because of overcapacity in these industries impairing our profitability;
- our inability to maintain satisfactory labor relations;
- coal users switching to other fuels in order to comply with various environmental standards related to coal combustion emissions;

- the impact of potential, as well as any adopted regulations relating to greenhouse gas emissions on the demand for coal and natural gas
- foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;
- the risks inherent in coal and natural gas operations being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, explosions, accidents and weather conditions which could impact financial results;
- decreases in the availability of, or increases in, the price of commodities or capital equipment used in our mining operations;
- decreases in the availability of, an increase in the prices charged by third party contractors or, failure of third party contractors to provide quality services to us in a timely manner could impact our profitability;
- obtaining and renewing governmental permits and approvals for our coal and gas operations;
- the effects of government regulation on the discharge into the water or air, and the disposal and clean-up of, hazardous substances and wastes generated during our coal and natural gas operations;
- our ability to find adequate water sources for our use in gas drilling, or our ability to dispose of water used or removed from strata in connection with our gas operations at a reasonable cost and within applicable environmental rules;
- the effects of stringent federal and state employee health and safety regulations, including the ability of regulators to shut down a mine or natural gas well;
- the potential for liabilities arising from environmental contamination or alleged environmental contamination in connection with our past or current coal and gas operations;
- the effects of mine closing, reclamation, gas well closing and certain other liabilities;
- uncertainties in estimating our economically recoverable coal and gas reserves;
- costs associated with perfecting title for coal or gas rights on some of our properties;
- the impacts of various asbestos litigation claims;
- the outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;
- increased exposure to employee-related long-term liabilities;
- our accruals for obligations for long-term employee benefits are based upon assumptions which, if inaccurate, could result in our being required to expend greater amounts than anticipated;
- due to our participation in an underfunded multi-employer pension plan, we have exposure under that plan that extends beyond what our obligation would be with respect to our employees and in the future we may have to make additional cash contributions to fund the pension plan or incur withdrawal liability;
- lump sum payments made to retiring salaried employees pursuant to our defined benefit pension plan exceeding total service and interest cost in a plan year;
- acquisitions and joint ventures that we recently have completed or entered into or may make in the future including the accuracy of our assessment of the acquired businesses and their risks, achieving any anticipated synergies, integrating the acquisitions and unanticipated changes that could affect assumptions we may have made and divestitures we anticipate may not occur or produce anticipated proceeds including joint venture partners paying anticipated carry obligations;
- the terms of our existing joint ventures restrict our flexibility and actions taken by the other party in our gas joint ventures may impact our financial position;
- the anti-takeover effects of our rights plan could prevent a change of control;
- risks associated with our debt;
- replacing our natural gas reserves, which if not replaced, will cause our gas reserves and gas production to decline;
- our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- other factors discussed in our 2011 Form 10-K under “Risk Factors,” as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In addition to the risks inherent in operations, CONSOL Energy is exposed to financial, market, political and economic risks. The following discussion provides additional detail regarding CONSOL Energy's exposure to the risks of changing commodity prices, interest rates and foreign exchange rates.

CONSOL Energy is exposed to market price risk in the normal course of selling natural gas production and to a lesser extent in the sale of coal. CONSOL Energy sells coal under both short-term and long-term contracts with fixed price and/or indexed price contracts that reflect market value. CONSOL Energy uses fixed-price contracts, collar-price contracts and derivative commodity instruments that qualify as cash-flow hedges under the Derivatives and Hedging Topic of the Financial Accounting Standards Board Accounting Standards Codification to minimize exposure to market price volatility in the sale of natural gas. Our risk management policy prohibits the use of derivatives for speculative purposes.

CONSOL Energy has established risk management policies and procedures to strengthen the internal control environment of the marketing of commodities produced from its asset base. All of the derivative instruments without other risk assessment procedures are held for purposes other than trading. They are used primarily to mitigate uncertainty, volatility and cover underlying exposures. CONSOL Energy's market risk strategy incorporates fundamental risk management tools to assess market price risk and establish a framework in which management can maintain a portfolio of transactions within pre-defined risk parameters.

CONSOL Energy believes that the use of derivative instruments, along with our risk assessment procedures and internal controls, mitigates our exposure to material risks. However, the use of derivative instruments without other risk assessment procedures could materially affect CONSOL Energy's results of operations depending on market prices. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity.

For a summary of accounting policies related to derivative instruments, see Note 1—Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of CONSOL Energy's 2011 Form 10-K.

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at September 30, 2012. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $23.5 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $23.5 million.

CONSOL Energy’s primary exposure to market risk for changes in interest rates relates to our revolving credit facility, under which there were no borrowings outstanding at September 30, 2012. Also, CNX Gas had no borrowings under its revolving credit facility at September 30, 2012.

Almost all of CONSOL Energy’s transactions are denominated in U.S. dollars, and, as a result, it does not have material exposure to currency exchange-rate risks.

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Hedging Volumes

As of October 19, 2012 our hedged volumes for the periods indicated are as follows:

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2012 Fixed Price Volumes					
Hedged Mcf	19,108,632	19,108,632	19,318,617	19,318,617	76,854,498
Weighted Average Hedge Price/Mcf	$5.25	$5.25	$5.25	$5.25	$5.25
2013 Fixed Price Volumes					
Hedged Mcf	16,114,849	16,293,903	16,472,957	16,472,957	65,354,666
Weighted Average Hedge Price/Mcf	$4.73	$4.73	$4.73	$4.73	$4.73
2014 Fixed Price Volumes					
Hedged Mcf	13,559,838	13,710,502	13,861,167	13,861,167	54,992,674
Weighted Average Hedge Price/Mcf	$4.95	$4.95	$4.95	$4.95	$4.95
2015 Fixed Price Volumes					
Hedged Mcf	8,240,277	8,331,836	8,423,395	8,423,395	33,418,903
Weighted Average Hedge Price/Mcf	$4.07	$4.07	$4.07	$4.07	$4.07

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures. CONSOL Energy, under the supervision and with the participation of its management, including CONSOL Energy’s principal executive officer and principal financial officer, evaluated the effectiveness of the Company’s “disclosure controls and procedures,” as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on that evaluation, CONSOL Energy’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures are effective as of September 30, 2012 to ensure that information required to be disclosed by CONSOL Energy in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by CONSOL Energy in such reports is accumulated and communicated to CONSOL Energy’s management, including CONSOL Energy’s principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal controls over financial reporting. There were no changes in the Company's internal controls over financial reporting that occurred during the fiscal quarter covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS
The first through the nineteenth paragraphs of Note 11—Commitments and Contingencies in the Notes to the Unaudited Consolidated Financial Statements included in Item 1 of this Form 10-Q are incorporated herein by reference.

ITEM 1A. RISK FACTORS
We have entered into two significant gas joint ventures. These joint ventures restrict our operational and corporate flexibility; actions taken by our joint venture partners may materially impact our financial position and results of operation; and we may not realize the benefits we expect to realize from these joint ventures.

In the second half of 2011 CONSOL Energy, through its principal gas operations subsidiary, CNX Gas Company LLC (CNX Gas Company), entered into joint venture arrangements with Noble Energy, Inc. (Noble Energy) and Hess Ohio Developments, LLC (Hess) regarding our shale gas assets. We sold a 50% undivided interest in approximately 628 thousand net acres of Marcellus shale oil and gas assets to Noble Energy and a 50% undivided interest in nearly 200 thousand net Utica shale acres in Ohio. The following aspects of these joint ventures could materially impact CONSOL Energy:

- The development of these properties is subject to the terms of our joint development agreements with these parties and we no longer have the flexibility to control the development of these properties. For example, the joint development agreements for each of these joint ventures sets forth required capital expenditure programs that each party must participate in unless the parties mutually agree to change such programs or, in certain limited circumstances in the case of the Noble Energy joint development agreement, a party elects to exercise a non-consent right with respect to an entire year. If we do not timely meet our financial commitments under the respective joint venture agreements, our rights to participate in such joint ventures will be adversely affected and the other parties to the joint ventures may have a right to acquire a share of our interest in such joint ventures proportionate to, and in satisfaction of, our unmet financial obligations. In addition, each joint venture party has the right to elect to participate in all acreage and other acquisitions in certain defined areas of mutual interest.
- Each joint development agreement assigns to each party designated areas over which that party will manage and control operations. We could incur liability as a result of action taken by one of our joint venture partners.
- Of the approximately \$3.3 billion we anticipate receiving from Noble Energy, approximately \$2.1 billion depends upon Noble Energy paying a portion of our share of drilling and development costs for new wells, which we call “carried costs.” We entered into a similar transaction with Hess Ohio Developments, LLC (Hess) in which approximately \$534 million of the total anticipated consideration of \$594 million is dependent upon Hess paying carried costs. Thus, the benefits we anticipate receiving in the joint ventures depend in part upon the rate at which new wells are drilled and developed in each joint venture, which could fluctuate significantly from period to period. Moreover, the performance of these third party obligations is outside our control. The inability or failure of a joint venturer to pay its portion of development costs, including our carried costs during the carry period, could increase our costs of operations or result in reduced drilling and production of oil and gas or loss of rights to develop the oil and gas properties held by that joint venture;
- Noble Energy's obligation to pay carried costs is suspended if average Henry Hub natural gas prices fall and remain below \$4.00 per million British thermal units or “MMBtu” in any three consecutive month period and will remain suspended until average natural gas prices are above \$4.00/MMBtu for three consecutive months. As a result of this provision, Noble Energy's obligation to pay carried costs was suspended beginning on December 1, 2011. We cannot predict when this suspension will be lifted and Noble Energy's obligation to pay the carried costs will resume. This suspension has the effect of requiring us to incur our entire 50 percent share of the drilling and completion costs for new wells during the suspension period and delaying receipt of a portion of the value we expect to receive in the transaction.

- The Noble Energy joint development agreement prohibits prior to March 31, 2014, unless Noble Energy consents in its sole discretion, any transfer of our interests in the Noble Energy joint venture assets or our selling or otherwise transferring control of CNX Gas Company. The Hess joint development agreement prohibits prior to October 21, 2014, unless Hess consents in its sole discretion, any transfer of our interests in the Hess joint venture assets. These restrictions may preclude transactions which could be beneficial to our shareholders.
- Disputes between us and our joint venture partners may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

Under the joint venture agreements, our joint venture partners have the right for a specified period of time to perform due diligence on the title to the oil and gas interests which we conveyed to them. To the extent our joint venture partners assert claims for title defects, we have a specified period of time in which to review and respond to the asserted title defects, as well as to cure them. We are currently in the this review process with Noble and Hess. If Noble or Hess establish any title defects which are not resolved or if the subject acreage is reassigned to CONSOL, then subject to certain deductibles, their aggregate carried cost obligation under the respective joint venture agreements will be reduced by the value the parties previously allocated to the affected acreage in the respective transactions. If a significant percentage of the oil and gas interests we contributed have title defects, the carried costs could be materially reduced and our aggregate share of the drilling and completion costs for wells in these joint ventures could materially increase.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in exhibit 95 to this quarterly report.

ITEM 6. EXHIBITS

31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data.
101	Interactive Data File (Form 10-Q for the quarterly period ended September 30, 2012 furnished in XBRL).

In accordance with SEC Release 33-8238, Exhibits 32.1 and 32.2 are being furnished and not filed.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Dated: November 1, 2012

CONSOL ENERGY INC.

By: /S/ J. BRETT HARVEY
J. Brett Harvey
Chairman of the Board and Chief Executive Officer
(Duly Authorized Officer and Principal Executive Officer)

By: /S/ WILLIAM J. LYONS
William J. Lyons
Chief Financial Officer and Executive Vice President
(Duly Authorized Officer and Principal Financial and Accounting Officer)